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Industrial Boiler SO2 Cost Report

Radian Corp., Research Triangle Park, NC

Prepared for

Environmental Protection Agency
Research Triangle Park, NC

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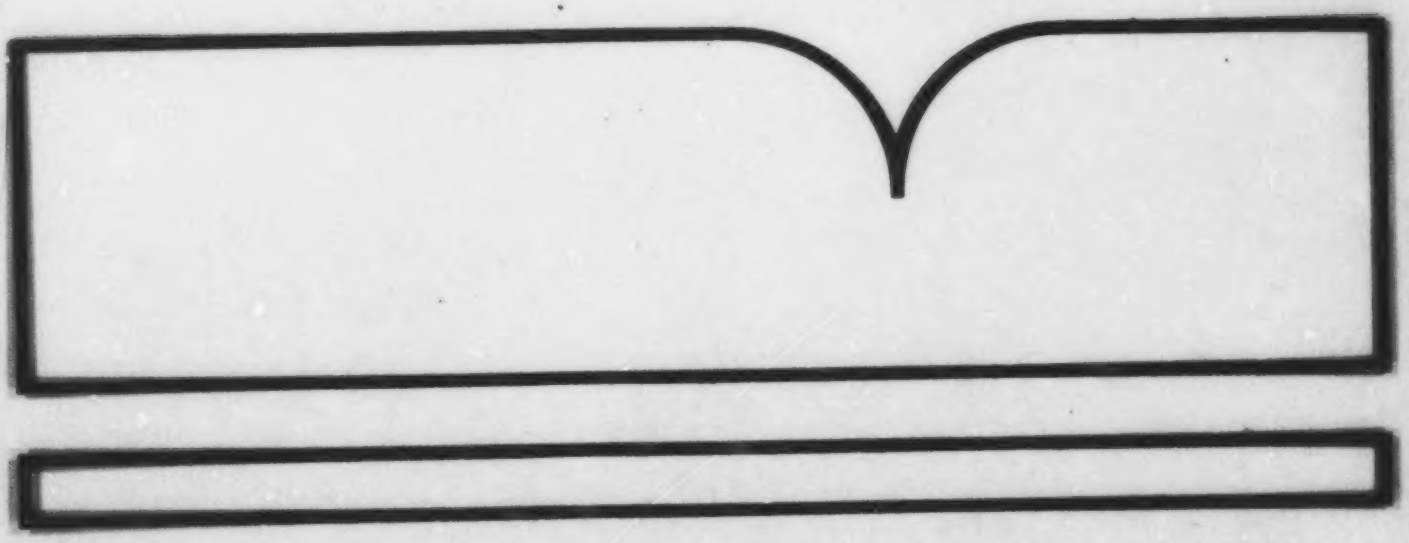

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16. ABSTRACT

This report is a resource document for the development of Federal standards of performance for control of sulfur dioxide emissions for new industrial boilers. It presents capital and annualized costs for SO_2 control technologies applied to coal- and residual oil-fired industrial boilers. Control costs are presented for model boilers with heat input capacities of 100, 150, 250, and 400 million Btu per hour firing fuels with various sulfur contents and achieving 50, 70, and 90 percent SO_2 reduction using flue gas desulfurization systems. The cost algorithms used to calculate these costs are also presented.

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1.0 INTRODUCTION

This report presents a cost analysis of alternative sulfur dioxide (SO_2) controls on coal- and residual oil-fired industrial boilers in EPA Regions V (Midwest) and VIII (North Central). Alternative SO_2 controls examined included the use of various low-sulfur fuels and flue gas desulfurization (FGD) techniques. For each alternative control method, the capital costs, operating and maintenance costs, and annualized costs are presented.

Chapter 2 discusses the methodologies and cost bases for estimating boiler and control costs. Chapter 3 presents the capital and annualized costs for coal-fired model boilers, and Chapter 4 presents costs for residual oil-fired model boilers.

Two appendices are also included for reference. Appendix A is a listing of the cost algorithms used to estimate the boiler, PM control, SO_2 control, and NO_x control costs. These algorithms are all based on mid-1978 dollars. The cost basis used in this report corresponds to January 1983 dollars. The factors used to convert algorithm costs to this later basis are presented in Appendix B. Appendix B also provides factors for adjusting report costs to other bases selected by the reader.

2.0 COSTING METHODOLOGY

This chapter presents the methodologies and bases used to calculate the costs of model boilers and SO_2 controls presented in Chapters 3 and 4 of this report. Section 2.1 discusses the basic costing approach used in calculating capital, operating and maintenance, and annualized costs for boilers and control devices. The specific equipment specifications used to calculate the model boiler and control device costs are presented in Section 2.2. Lastly, Section 2.3 discusses other cost considerations such as continuous emission measurement costs, FGD malfunction costs, and regional cost differences.

2.1 COSTING APPROACH

In this report, the cost impacts of applying SO_2 controls to various types and sizes of industrial boilers are assessed through an analysis of "model boilers". These model boilers are selected to represent the population of new industrial boilers expected to be built in the future, and thus cover a range of boiler sizes, fuel types, and SO_2 control methods. The costs of each model boiler can be broken down into three major cost categories:

- Capital Costs (total capital investment required to construct and make operational a boiler and control systems),
- Operation and Maintenance (O&M) costs (total annual cost necessary to operate and maintain a boiler and control systems), and
- Annualized Costs (total O&M costs plus annualized capital-related charges).

Each of these cost categories can be further subdivided into individual cost components. Sections 2.1.1, 2.1.2, and 2.1.3 present the individual cost

components and the methods used to develop the capital, O&M, and annualized costs, respectively, for each of the model boilers.

2.1.1 Capital Costs

Table 2-1 presents the individual components of capital cost and the general methodology used for calculating total capital costs. Direct capital costs consist of the basic and auxiliary equipment costs in addition to the labor and material required to install the equipment. Equipment and installation costs for boilers and control systems are calculated using the algorithms presented in Appendix A. Section 2.2 of this report discusses the bases for each of these algorithms.

Other capital cost components are calculated using the factors shown in Table 2-1. Indirect costs are those costs not attributable to specific equipment items. Contingencies are included in capital costs to compensate for unpredicted events and other unforeseen expenses. However, in some cases, factors for indirect costs and contingencies different from those shown in Table 2-1 may be used. For example, in the cases of dual alkali and dry scrubbing FGD systems for boilers with heat inputs of 58 MW (200 million Btu/hr) or less, engineering costs are calculated as 10 percent of the total direct costs for an FGD system applied to a 58 MW (200 million Btu/hr) boiler. And for sodium scrubbing FGD systems, turnkey capital costs are calculated directly, based on vendor and plant cost data.

The interest cost incurred during the period of construction of the boiler and associated control equipment is also included in the boiler total capital costs as a function of the turnkey capital cost. It is assumed that payment terms for boilers and control equipment typically consist of a down payment of approximately 20 percent of the turnkey capital cost with the balance paid in equal progress payments over the period of construction and startup. The interest cost is a function of turnkey cost, interest rate, period of construction and total number of equal progress payments. The equations used to calculate interest cost are shown in Table 2-2. Table 2-3 lists the construction period and the interest during construction factors as a function of turnkey capital cost.[3]

TABLE 2-1. CAPITAL COST COMPONENTS[a]

(1)	Direct Costs	
	Equipment	
	+ Installation	
	= Total Direct Costs	
(2)	Indirect Costs	
	Engineering (10 % of total direct costs)[b]	
	+ Construction and Field Expenses	(10% of total direct costs)[b]
	+ Construction Fees	(10% of total direct costs)[b]
	+ Start Up Costs	(2% of total direct costs)[b]
	+ Performance Costs	(1% of total direct costs)[c]
	= Total Indirect Costs	
(3)	Contingencies[b] = 20% of (Total Indirect + Total Direct Costs)	
(4)	Total Turnkey Cost = Total Indirect Cost + Total Direct Cost + Contingencies	
(5)	Interest During Construction[d]	
(6)	Working Capital[e]	
(7)	Land[f]	
(8)	Total Capital Cost = Total Turnkey + Interest During Construction + Working Capital + Land	

[a]Boiler and each control system costed separately; factors apply to cost of boiler or control system considered; i.e., the engineering cost for the PM control system is 10% of the direct cost of the PM control system.

[b]Reference 1.

[c]Reference 2.

[d]See Tables 2-2 and 2-3.

[e]See Table 2-4.

[f]Land costs for boiler and control system are included in capital cost of boiler.

TABLE 2-2. CALCULATION OF INTEREST COSTS DURING CONSTRUCTION[a]

Assume: interest (i) = 10 percent effective annual rate

terms = 20 percent of total turnkey capital cost paid at contract award and balance paid in equal monthly installments over the period of construction.

Future value of the 20 percent down payment is found by using the compound interest law or,

$S = P\,(1 + i)^n$, where S = Future Value
P = Present Worth
n = Number of years

Future value of the equal monthly installments is calculated by the following equation:

$$S = \frac{R(1 + i/m)^{mn} - 1}{(1 + i/m)^{m/p} - 1}$$

R = Equal payment = P/np
m = No. of times compounded per year = 1
n = No. of years (see Table 2-3)
p = No. of payments per year = 12

Combining the two equations yields,

$$S = 0.2\,P\,(1 + i)^n + 0.80\,\frac{P}{np}\left(\frac{(1 + i/m)^{mn} - 1}{(1 + i/m)^{m/p} - 1}\right)$$

[a]Reference 3 and 4.

TABLE 2-3. CONSTRUCTION PERIODS AND INTEREST-DURING-CONSTRUCTION FACTORS

Boiler or Control Equipment	Approximate Construction Period (Months)[a]	Interest During Construction Factor[b]
Boilers and NO_x Control:		
For Packaged Oil and Gas-fired Boilers	12	IDC = 0.056 * TK[c,d]
For Field-erected Oil and Gas Boilers	18	IDC = 0.087 * TK
For Coal-fired Boilers $\leq$ 150 MM Btu/hr	20	IDC = 0.095 * TK
For Coal-fired Boilers > 150 MM Btu/hr	24	IDC = 0.120 * TK
For PM Control:		
For Q $\leq$ 150 MM Btu/hr	8	IDC = 0.036 * TK
For Q > 150 MM Btu/hr	11	IDC = 0.051 * TK
For SO_2 Control:		
Sodium Scrubbing: all sizes	6.75	IDC = 0.030 * TK
Dry Scrubbing: all sizes	27	IDC = 0.137 * TK
Dual Alkali: all sizes	27	IDC = 0.137 * TK

[a]Reference 3.

[b]All factors are based on 10% effective annual interest rate.

[c]IDC = interest costs during construction.

[d]TK = turnkey capital cost.

Costs of land for the boiler and control system are all included in boiler capital costs. All model boilers except pulverized coal boilers are assumed to require one acre of land and have land costs of $2,800. Pulverized coal boilers are assumed to require two acres of land and have land costs of $5,700.[1]

The computation of working capital requirements for fuel and non-fuel items differs slightly as shown in Table 2-4. These equations are based on three months of direct annual non-fuel operating costs and one month of fuel costs.

2.1.2 Operation and Maintenance (O&M) Costs

Table 2-5 lists the individual cost components and the general methodologies used in calculating total O&M costs. Direct O&M costs include operating, supervisory, and maintenance labor, fuel, utilities, replacement parts, supplies, waste disposal and chemicals. Direct O&M costs for model boilers and control systems are calculated using the algorithms presented in Appendix A. Indirect operating costs include payroll and plant overhead and are calculated based on a percentage of some key O&M cost components (e.g. operating labor, supervisory labor, maintenance labor, and replacement parts).

Table 2-6 presents the unit costs for utilities, raw materials, waste disposal, and labor used in calculating non-fuel O&M costs for the boilers and control equipment. The largest O&M cost for boilers is fuel. Fuel costs and specifications such as heating value, sulfur content, and ash content for coals and residual oils used in this analysis are presented in Chapters 3 and 4, respectively.

Operating and maintenance costs incurred are dependent upon the boiler capacity utilization, defined as the actual annual fuel consumption as a percentage of the potential annual fuel consumption at maximum firing rate. Fuel costs, raw material costs, utility costs, and waste disposal costs decrease in direct proportion to the capacity utilization factor. However, labor costs do not decrease in direct proportion due to shift manpower requirements. In order to account for reduced labor costs for boilers

TABLE 2-4. WORKING CAPITAL CALCULATIONS FOR BOILERS AND CONTROL DEVICES

Working Capital (WC)
Boilers - Assume three months of direct annual non-fuel operating costs and one month of fuel costs
WC^a = 0.25 (Direct annual non-fuel operating costs) + 0.083 (Fuel costs)
Control Equipment - Assume three months of direct annual operating costs
WC^b = 0.25 (Direct annual operating costs)

[a]Reference 5.

[b]Reference 1.

TABLE 2-5. OPERATING AND MAINTENANCE COST COMPONENTS[a]

(1)	Direct Operating Costs
	Operating Labor
+	Supervision
+	Maintenance Labor, Replacement Parts and Supplies
+	Electricity
+	Water
+	Steam
+	Waste Disposal
	Solids (Fly ash and bottom ash)
	Sludge
	Liquid
+	Chemicals
	Total Non-Fuel O&M
+	Fuel
=	Total Direct Operating Costs
(2)	Indirect Operating Costs (Overhead)[b]
	Payroll (30% Operating Labor)
+	Plant (26% of Operating Labor + Supervision + Maintenance Costs + Replacement Parts)
(3)	Total Annual Operating and Maintenance Costs = Total Direct + Total Indirect Costs

[a]Boilers and control systems are costed separately; factors apply to boiler or control system being considered, (i.e., payroll overhead for FGD system is 30% of the labor requirement for the FGD system).

[b]Factors recommended in Reference 6.

TABLE 2-6 UNIT COSTS USED IN CALCULATIONS[a,b]

Utilities		
	Electricity	$0.0390/Kwh
	Water	$0.06/$m^3$ ($0.23/$10^3$ gal)
	Steam	$4.55/GJ ($5.3/10^3 lb)
Raw Materials		
	Na_2CO_3	$0.150/kg ($136/ton)
	Lime	$0.059/kg ($53/ton)
	Limestone	$0.014/kg ($12/ton)
Labor		
	Direct Labor	$18.15/man-hour
	Supervision	$23.60/man-hour
	Maintenance Labor	$22.09/man-hour
Waste Disposal		
	Solids (Ash, Spray Dried Solids)	$0.0251/kg ($23/ton)
	Sludge	$0.0251/kg ($23/ton)
	Liquid	$0.88/$m^3$ ($0.60/$10^3$ gal)

[a]All costs in January 1983 $. Updated from 1978 using a multiplier of 1.51 (see Appendix B).

[b]Reference 7.

operating at reduced capacity utilization, the algorithms also incorporate labor factors. Table 2-7 presents the capacity utilization factors and corresponding labor factors assumed for various model boilers.

2.1.3 Annualized Costs

Total annualized costs are the sum of the annual O&M costs and the annualized capital charges. The annualized capital charges include the payoff of the capital investment (capital recovery), interest on working capital, general and administrative costs, taxes (real estate and local taxes but not corporate taxes), and insurance.

Table 2-8 presents the methods used in this report to calculate the individual annualized capital charge components. The capital recovery cost is determined by multiplying the capital recovery factor, which is based on the real interest rate and the equipment life, by the total turnkey costs (see Table 2-8). For this analysis a 10 percent real interest rate and a 15 year equipment life are assumed for the boilers and control equipment. This translates into a capital recovery factor of 13.15 percent. The real interest rate of 10 percent was selected as a typical constant dollar rate of return on investment to provide a basis for calculation of capital recovery charges. This interest rate is the "real" interest rate above and beyond inflation.

Table 2-8 also presents the methods used to calculate other components of the annualized capital charges. Interest on working capital is based on a 10 percent interest rate. The remaining components (general and administrative costs, taxes, and insurance) are estimated as 4 percent of total turnkey costs.

2.2 BOILER AND CONTROL DEVICE SPECIFICATIONS

Direct capital and direct O&M costs for model boilers and PM, NO_x, and SO_2 control techniques are estimated in this report by the use of cost "algorithms". Each algorithm is an algebraic function which projects capital and O&M costs for a particular system based on key process

TABLE 2-7. CAPACITY UTILIZATION AND LABOR FACTORS USED FOR MODEL BOILER COST CALCULATIONS[a]

Boiler Type	Capacity Utilization Factor (CF)	Labor Factor (LF)
Coal-fired (Spreader stoker, pulverized coal)	0.60	0.75
Residual oil-fired	0.55	0.62

Labor Factor Equations

CF	LF
>0.7	1
0.5 - 0.7	0.5 + 2.5 (CF - 0.5)
<0.5	0.5

[a]References 5 and 8.

TABLE 2-8. ANNUALIZED COST COMPONENTS

(1) Total Annualized Cost = Annual O&M Costs + Capital Charges

(2) Capital Charges = Capital recovery + interest on working capital + miscellaneous (G&A, taxes and insurance)

(3) Calculation of Capital Charges Components

A. Capital Recovery = Capital Recovery Factor (CRF) x Total Turnkey Cost

$$CRF = \frac{i\,(1 + i)^n}{(1 + i)^n - 1}$$

i = interest rate

n = number of years of useful life of boiler or control system

Item	n	i	CRF
Boiler, control systems	15	10	0.1315

B. Interest on Working Capital = 10% of working capital[a]

C. G&A, taxes and insurance = 4% of total turnkey cost[a]

[a]Reference 1.

parameters (e.g., heat input to boiler, SO_2 removal efficiency, capacity utilization factor, flue gas flow rate). The boiler and emission control costing algorithms used in this report are provided in Appendix A. It should be noted that the algorithms in Appendix A are given in 1978 dollars. The cost factors used to update the 1978 estimates to January 1983 dollars are presented in Appendix B. It should also be noted that all algorithms are based on a Midwest (i.e., Region V) boiler location. However, these algorithms can be used to predict costs in any other region of the U.S. (see Section 2.3.3 for discussion of regional cost differences).

The battery limits of the boiler extend from the fuel-receiving equipment to the ash disposal operation. Excluded are steam and condensate piping beyond the boiler building. Costs of ducting and the stack are also included in the battery limits of the boiler. Battery limits of the PM, NO_x, and SO_2 emission control systems include the control devices themselves, auxiliaries, raw material handling, waste disposal, and any additional ducting required. The specific equipment lists and assumptions used to develop the various algorithms are discussed in the following sections.

2.2.1 Uncontrolled Boiler Costs

This section presents the specific cost assumptions and methodologies that were used to calculate the industrial boiler costs presented in Chapters 3 and 4. References 8 and 9 detail the specific equipment lists and assumptions used to develop the boiler algorithms presented in Appendix A (Tables A-4 through A-7).

All of the coal-fired model boilers in this analysis are field-erected units. In addition, all coal-fired boilers have the same heat transfer configuration in that they are watertube units, although the firing mechanism varies according to size. Model boilers with heat inputs of less than 73 MW (250 million Btu/hr) are assumed to be spreader stokers and larger model boilers are assumed to fire pulverized coal. All of the residual oil-fired model boilers in this analysis are package watertube units designed with the capability of firing residual oil or natural gas.

All boiler costs are based on a new boiler constructed at a new plant in the Midwest. It is assumed that new plants will operate multiple boilers rather than one boiler where economically justified. Annual O&M costs such as labor, utilities, chemicals, spare parts and ash disposal will be reduced per boiler because of the economies of scale. To account for the O&M cost reductions associated with multiple boiler installations, multipliers for the annual O&M costs are incorporated into the algorithms presented in Appendix A. These multipliers are presented in Table 2-9. These multipliers are not included in the PM, NO_x, or SO_2 control algorithms, however. It is assumed that a single PM and/or SO_2 control system will be used at each facility regardless of the number of boilers used. And, the major component of NO_x control O&M costs is fuel cost (or savings), which does not exhibit economies of scale.

The boiler specifications presented in Tables 2-10 and 2-11 have been used to calculate the boiler capital costs presented in this report. It is assumed that all boilers operate under low excess air firing conditions. The flue gas flow rates for various model boilers are calculated using the algorithms presented in Appendix A (Table A-15).

2.2.2 Particulate Matter (PM) Control Costs

The algorithm used to calculate capital and operating costs for PM control on coal-fired boilers is presented in Appendix A (Table A-8). The cost algorithm for reverse-air fabric filters for coal-fired boilers was developed by PEDCo, Inc.[10] Table 2-12 lists the general specifications for a reverse-air fabric filter. It is assumed that no separate PM control is required for residual oil-fired boilers; it is assumed that the small amount of PM generally emitted by oil-fired boilers can be controlled through the use of FGD systems for SO_2 control or through the use of low sulfur/low ash oils.

2.2.3 NO_x Control Costs

The algorithms used to calculate capital and operating costs for NO_x control devices are presented in Appendix A (Tables A-12 through A-14). The

TABLE 2-9. DIRECT O&M MULTIPLIERS TO ACCOUNT FOR ECONOMIES ASSOCIATED WITH MULTIPLE BOILER INSTALLATIONS[a]

	Multiplier
Coal-Fired Boilers:	
Utilities, chemicals, and ash disposal	0.848
All labor, replacement parts, and overhead	0.767
Residual Oil-Fired Boilers:	
Utilities and chemicals	0.845
All labor, replacement parts, and overhead	0.799

[a]Reference 5.

TABLE 2-10. SPECIFICATIONS FOR COAL-FIRED MODEL BOILERS

Thermal input, MW (10^6 Btu/hr)	29.0 (100)	44.0 (150)	73.0 (250)	117.2 (400)
Fuel firing method	Spreader stoker	Spreader stoker	Pulverized coal	Pulverized coal
Excess air, %	35	35	35	35
Flue gas flow rate,[a] m^3/s (acfm)	-	-	-	-
Load factor, %	60	60	60	60
Efficiency (%)	80.0	80.9	82.0	83.1
Steam quality				
Pressure, kPa (psig)	3100 (450)	3100 (450)	5170 (750)	5170 (750)
Temperature, °k (°F)	590 (600)	590 (600)	670 (750)	670 (750)

[a]Dependent upon coal heating value. See Table A-15 to calculate flue gas flow rate for various coal types.

TABLE 2-11. SPECIFICATIONS FOR RESIDUAL OIL-FIRED MODEL BOILERS

Thermal input, MW (10^6 Btu/hr)	29.0 (100)	44.0 (150)	73.0 (250)	117 (400)
Excess air, %	9.1	9.1	9.1	9.1
Flue gas flow rate, m^3/s (acfm)[a]	14.1 (30,000)	21.2 (45,000)	35.4 (75,100)	56.6 (120,000)
Load factor, %	55	55	55	55
Efficiency (%)	85.0	85.0	85.0	85.0
Steam quality				
Pressure, kPa (psig)	5170 (750)	5170 (750)	5170 (750)	5170 (750)
Temperature, °K (°F)	670 (750)	670 (750)	670 (750)	670 (750)

[a]Based on a heating value of 43,000 kJ/kg (18,500 Btu/lb).

TABLE 2-12. GENERAL DESIGN SPECIFICATIONS FOR PM CONTROL SYSTEMS

Control Device	Item	Specification
Fabric Filter (FF) for coal-fired boilers	Material of Construction	Carbon steel (insulated)
	Cleaning method	Reverse-air (multi-compartment)
	Air to cloth ratio	2 ft/min
	Bag material	Teflon-coated fiberglass
	Bag life	2 years
	Pressure drop[a]	6 in. H_2O gauge

[a]Pressure drop refers to gas-side pressure drop across entire control system.

cost algorithms for low excess air (LEA) operation, and staged combustion (SCA) were developed by Radian based on costs presented in the Individual Technology Assessment Report (ITAR) for NO_x Combustion Modification.[11] Table 2-13 presents the general specifications for LEA and SCA.

2.2.4 SO_2 Control Costs

The cost algorithms used to calculate capital and annual operating costs for flue gas desulfurization units are also presented in Appendix A (Tables A-9 through A-11). The cost algorithms are based on information presented in the FGD ITAR and Reference 12, but are not exact representations of these costs. The ITAR costs were modified to reflect revised installation factors for double alkali FGD systems and revised fabric filter costs for spray drying FGD systems.[13,14] A revised cost algorithm for sodium scrubbing FGD systems was developed based on information received from vendors and plants;[15] this algorithm also includes wastewater treatment costs.[16,17]

The cost algorithms used to estimate FGD capital costs are based on shop-fabricated, or packaged, FGD units.[13] These algorithms were developed using techniques consistent with typical "budget-cost" estimates provided by vendors to clients in the preliminary stages of project evaluation. These estimates are considered accurate to within ±30 percent of the actual installed costs of FGD systems.

Table 2-14 presents the general specifications for the FGD systems analyzed in this report. These specifications are typical for FGD systems currently in use.

2.3 OTHER COST CONSIDERATIONS

This section addresses additional cost considerations that may be incurred by boiler operators and/or regulatory agencies that have not been addressed in Section 2.2. Section 2.3.1 presents costs associated with continuous emission measurement, Section 2.3.2 presents the costs of

TABLE 2-13. NO_x COMBUSTION MODIFICATION EQUIPMENT REQUIREMENTS OR MODIFICATIONS

Control Device	Specification
Low Excess Air (LEA)	Oxygen trim system - O_2 analyzer, air flow regulators
	Wind box modifications (may be required for multi-burner boilers)
Staged Combustion Air (SCA) Pulverized coal-fired boilers:	Oxygen trim system - O_2 analyzer, air flow regulators
	Air ports
	Wind box modifications
	Larger forced draft fan power
Residual oil-fired boilers:	Oxygen trim system - O_2 analyzer, air flow regulators
	Up to 30 percent larger boiler to accommodate longer flame

TABLE 2-14. GENERAL DESIGN SPECIFICATIONS FOR FGD SYSTEM FOR SO_2 CONTROL

Control Device	Item	Specification
Double Alkali FGD (SO_2 removal only) (DA)	Scrubber type	Tray tower
	Pressure drop[a]	8 in. H_2O
	L/G	10 gal/10^3 acf
	Scrubber sludge	60% solids
	Sludge disposal	Trucked to off-site landfill
Sodium Scrubbing FGD (SO_2 removal only) (SOD)	Scrubber type[a]	Spray baffle
	Pressure drop	8 in. H_2O
	L/G	40 gal/10^3 acf
	Disposal method	Oxidation and sewerage
Dry Scrubbing (spray drying, SO_2 and PM removal) (DS)	Material of construction	Carbon steel spray dryer and fabric filter (insulated)
	Reagent	Lime; with solids recycle at 2 kg recycle solids/kg fresh lime feed
	Fabric filter	Pulse jet; air-to-cloth ratio of 4 acfm/ft^2
	Pressure drop[a]	6 in. H_2O
	L/G	0.3 gal/acf
	Solids disposal	Trucked to off-site landfill

[a]All pressure drops refer to gas side pressure drop across entire control system.

requiring SO_2 control during periods of FGD malfunction, and Section 2.3.3 discusses the impacts of regional cost differences.

2.3.1 Continuous Emission Measurement Costs

Table 2-15 presents estimates for continuous emission measurement costs for opacity, NO_x, and SO_2.[18] Costs are shown in January 1983 dollars. For the purposes of this analysis, it is assumed that continuous NO_x monitors are required on all coal- and residual oil-fired boilers with a heat input capacity greater than 29 MW (100 million Btu/hour). Opacity monitors are required for all boilers except those equipped with wet FGD systems. Units with FGD are assumed to require continuous monitors for inlet and outlet SO_2 and a diluent (CO_2 or O_2) monitor. Units without FGD are assumed to require a single SO_2 monitor and a single diluent monitor at the outlet. An automatic data reduction system is included as part of monitoring costs for all model boilers. Continuous emission measurement costs shown in Table 2-15 are included in the total costs presented in subsequent chapters.

2.3.2 FGD Malfunction Costs[19]

In order to maintain compliance with applicable emission requirements during periods of FGD malfunction, several alternative methods of SO_2 control may be used. One alternative is to install a spare scrubbing unit for operation during FGD malfunction. However, sparing is a capital intensive alternative. Another alternative would be to fire low sulfur fuels such as natural gas, low sulfur oil, or low sulfur coal during FGD downtime. Nearly all new boilers will be designed for multi-fuel firing or will be installed at facilities where spare natural gas or low sulfur oil-fired boiler capacity is available. Therefore, there are essentially no additional capital costs associated with the firing of natural gas or low sulfur oil during malfunction.

Malfunction costs can vary as a function of boiler size, capacity factor, type of FGD system, FGD system reliability and differential cost between fuels fired during normal operation and during FGD malfunction. In general, however, malfunction costs represent less than 3 percent of the

TABLE 2-15. CONTINUOUS EMISSION MEASUREMENT COSTS (January 1983 $)[a,b]

System	Capital Cost ($1000)	O & M Cost ($1000/yr)	Annualized Cost ($1000/yr)
Opacity	57	8	15
NO_x	57	36	44
SO_2 (outlet only)	44	36	42
SO_2 (inlet and outlet)	64	72	81
O_2/CO_2 (outlet only)	9	8	9
O_2/CO_2 (inlet and outlet)	18	15	18

[a]Reference 18.

[b]See Section 2.3.1 for discussion of continuous emission measurement costs assumed for each model boiler.

total boiler annualized costs. In order to maintain consistency throughout this report, it is assumed that FGD operators fire natural gas during periods of malfunction. The FGD system reliability is assumed to be 95 percent.[20] Malfunction costs are included in the total annualized costs in subsequent chapters.

2.3.3 Regional Cost Considerations

Model boiler costs can vary on a regional basis due to differences in fuel price, labor rates, utility rates, raw material costs, and waste disposal costs. However, since fuel costs generally represent 50 to 75 percent of the total O&M costs for coal-fired boilers and 80 to 90 percent for residual oil-fired boilers, regional differences in fuel price have a much greater impact on regional model boiler costs than do non-fuel O&M components such as labor rates, etc.[21] Table 2-16 shows how fuel prices vary by Region and, for reference, Figure 2-1 depicts each region geographically.

This report presents costs for coal-fired model boiler in Regions V and VIII. As shown in Table 2-16, a large number of bituminous and subbituminous coals are readily available in Region V. Generally, only low- and medium-sulfur content bituminous and subbituminous coals are delivered to Region VIII. Table 2-16 also shows that coal prices in Region V do not differ significantly from prices in Regions I through VII. Coal prices in Regions VIII, IX, and X are typically lower than in the other regions, with Region VIII having the lowest prices anywhere in the U.S. Therefore, Regions V and VIII were selected for analysis in this report - Region V because it is representative of many other regions, and Region VIII because it has significantly lower coal prices than any other region in the U.S. Table 2-16 shows that regional variations in residual oil prices are not as important as variations in coal prices. In addition, the premium price for a low sulfur oil compared to high sulfur oil is essentially constant for all regions. Therefore, this report presents costs for residual oil-fired model boilers in Region V only. These costs should be representative of costs in all regions.

TABLE 2-16. REGIONAL FUEL PRICES IN $/10^6$ BTU (JANUARY 1983 $)[a,b,c]

Fuel Type	Sulfur Content ($lb\ SO_2/10^6$ Btu)[d]	REGION I	II	III	IV	V	VI	VII	VIII	IX	X
COAL											
Bituminous											
B	0.80 - 1.08	3.76	3.52	3.14	3.19	3.32	3.34	3.14	1.99	2.80	3.18
D	1.08 - 1.67	3.71	3.45	2.94	2.98	3.18	3.21	3.08	1.86	2.82	2.97
E	1.67 - 2.50	3.65	3.30	2.85	2.96	3.08	3.20	3.04	1.87	2.77	2.84
F	2.50 - 3.33	3.46	3.13	2.75	2.88	2.93	3.19	2.92	-	-	-
G	3.33 - 5.0	3.16	2.82	2.42	2.80	2.67	3.09	2.62	-	-	-
H	>5.00	3.26	2.85	2.39	2.62	2.50	2.96	2.47	-	-	-
Subbituminous											
B	0.80 - 1.08	-	-	-	-	3.38	3.49	2.74	1.40	2.84	2.66
D	1.08 - 1.67	-	-	-	-	3.34	3.39	2.69	1.39	2.74	2.60
E	1.67 - 2.50	-	-	-	-	3.30	3.32	2.72	1.28	2.65	2.09
RESIDUAL OIL 0.8 lb $SO_2/10^6$[e]	0.80	5.50	5.49	5.49	5.46	5.63	5.49	5.60	5.29	5.11	5.07
NATURAL GAS	-	5.83	5.79	5.73	6.02	5.88	5.41	5.45	4.91	5.44	5.57

[a] Reference 22.

[b] 1990 levelized fuel prices in January 1983 dollars.

[c] To convert $/10^6 Btu to $/kJ, multiply by 0.947.

[d] To convert $lb/10^6$ Btu to ng/J, multiply by 430.

[e] Subtract $0.70/10^6 Btu for 3.0 lb $SO_2/10^6$ Btu oil; subtract $0.38/10^6 Btu for 1.6 lb $SO_2/10^6$ Btu oil; add $0.37/10^6 Btu for 0.3 lb $SO_2/10^6$ Btu oil.

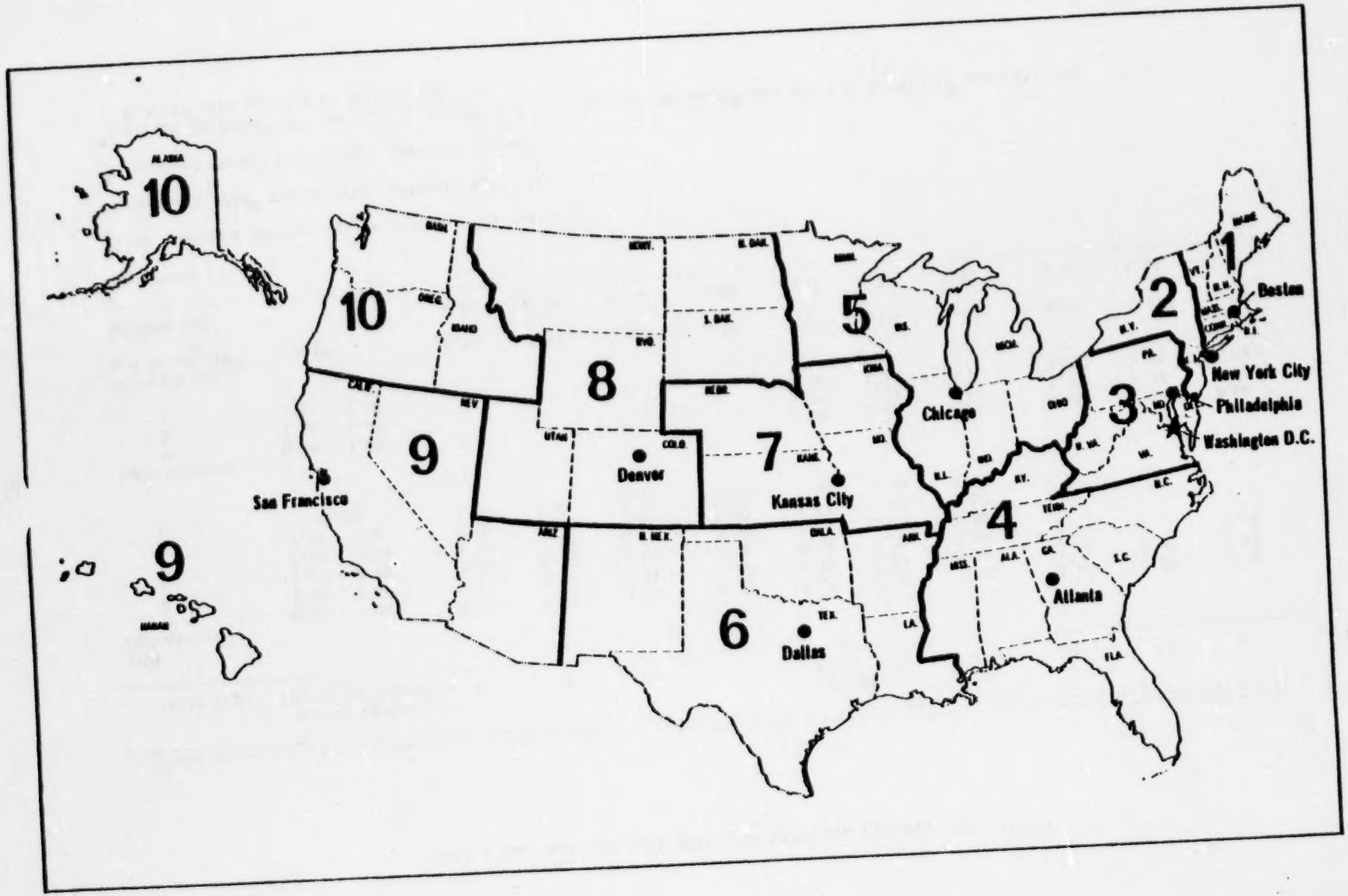

Figure 2-1. Federal Regions of the United States

It was assumed that all costs other than fuel (capital charges, non-fuel O&M costs) remain constant on a regional basis. Regional variations in labor rates, utility rates, raw materials costs and waste disposal costs can result in regional variations in absolute costs for any given alternative. However, the purpose of this analysis is not to compare the absolute costs of SO_2 control in various regions but rather to determine the difference in cost between various alternatives within a given region. In other words, the objective of this analysis is to determine the cost <u>difference</u> between a given SO_2 control alternative and the baseline alternative, and to determine whether that difference varies significantly from region to region.

The incremental cost of one alternative as compared to another includes differences in fuel prices and/or differences in the capital and operating costs of FGD systems. The variation in FGD capital and operating costs from region to region due to differences in labor rates, utility rates, raw material costs, and waste disposal costs is small in comparison to variations in regional fuel prices, and can therefore be neglected.[21] For this reason, the results presented here include only fuel price variations and assume all other unit costs are equal on a regional basis.

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3.0 COST OF SO_2 CONTROL ON COAL-FIRED MODEL BOILERS

This chapter presents the results of an analysis of SO_2 control costs for coal-fired model boilers in Region V and in Region VIII. Capital and annualized costs are examined for boilers with no SO_2 control (baseline) and for boilers equipped with FGD systems achieving 50 percent, 70 percent, and 90 percent SO_2 removal. Costs are examined for several boiler sizes and for numerous coal types. The boiler sizes selected for this analysis are 29, 44, 73 and 117 MW (100, 150, 250 and 400 million Btu/hr) heat input.

Specifications and prices of coals delivered to Region V and to Region VIII are presented in Table 3-1. To maintain consistency with the Industrial Fuel Choice Analysis Model (IFCAM), which is used to project the national impacts of alternative SO_2 standards, the values in Table 3-1 are projections for 1990 delivered fuel prices expressed in January 1983 dollars.[1] The projections ignore the effects of inflation but assume that fuel prices will escalate in real terms. In addition, the fuel prices have been "levelized" over the life of the boiler (i.e., an equivalent constant price has been calculated after allowing for escalation and the time value of money).

The PM and NO_x controls examined are the same under the baseline and for each of the SO_2 control alternatives selected. All model boilers are assumed to require a fabric filter for particulate matter control. Spreader stoker boilers [boilers with heat inputs of less than 73 MW (250 million Btu/hr)] are assumed to require the use of low-excess air (LEA) operation for NO_x control and pulverized coal boilers [boilers with heat inputs of 73 MW (250 million Btu/hr) or greater] are assumed to require staged combustion air (SCA) operation in addition to LEA.

Several types of FGD systems are available for control of SO_2 from industrial boilers, including double alkali, sodium scrubbing, and dry scrubbing FGD. Table 3-2 presents the costs for a 44 MW (150 million Btu/hr) boiler in Region V for each of the FGD systems above for two coal types. The same relative relationships as those shown in Table 3-2 would

TABLE 3-1. SPECIFICATIONS FOR COAL DELIVERED TO REGION V AND REGION VIII[a]

Coal Type	Uncontrolled SO_2 Ng/J ($lb/10^6$ Btu)	Fuel Price[b] $/kJ ($/10^6 Btu)	Heating Value kJ/kg (Btu/lb)	Sulfur Content Wt. %	Ash Content Wt. %
Region V:					
B-sub	409 (0.95)	3.20 (3.38)	20,524 (8,825)	0.42	6.9
D-sub	624 (1.45)	3.16 (3.34)	20,524 (8,825)	0.64	6.9
E-sub	903 (2.10)	3.13 (3.30)	20,524 (8,825)	0.93	6.9
B-bit	409 (0.95)	3.14 (3.32)	29,000 (12,500)	0.60	11.0
D-bit	624 (1.45)	3.01 (3.18)	29,300 (12,600)	0.91	11.0
E-bit	903 (2.10)	2.92 (3.08)	27,400 (11,800)	1.24	10.5
F-bit	1,226 (2.85)	2.77 (2.93)	26,700 (11,500)	1.64	10.9
G-bit	1,785 (4.15)	2.53 (2.67)	26,700 (11,500)	2.38	12.2
H-bit	2,382 (5.54)	2.37 (2.50)	27,200 (11,700)	3.23	12.0
Region VIII:					
B-sub	409 (0.95)	1.33 (1.40)	20,400 (8,770)	0.42	8.4
D-sub	624 (1.45)	1.32 (1.39)	20,000 (8,620)	0.63	6.9
E-sub	903 (2.10)	1.22 (1.28)	20,000 (8,620)	0.91	6.9
B-bit	409 (0.95)	1.88 (1.99)	25,300 (10,900)	0.52	10.0
D-bit	624 (1.45)	1.76 (1.86)	23,900 (10,300)	0.75	10.0
E-bit	903 (2.10)	1.77 (1.87)	23,900 (10,300)	1.08	10.0

[a]Reference 1.

[b]1990 levelized fuel price in 1983 $.

TABLE 3-2. PM/SO_2 CONTROL COSTS FOR A 44 MW (150 MILLION BTU/HR) MODEL BOILER IN REGION V[a,b] (JAN 1983 $)

	Sodium Scrubbing[c]			Dry Scrubbing[d]	Double Alkali[c]		
	Fabric Filter	FGD	Total	Total	Fabric Filter	FGD	Total
Capital Cost ($1000):							
High Sulfur Bituminous Coal[e]	1,549	919	2,468	3,102	1,549	2,403	3,952
Low Sulfur Subbituminous Coal[f]	1,607	698	2,305	2,617	1,607	1,894	3,501
Annualized Cost ($1000/yr):							
High Sulfur Bituminous Coal[e]	419	919	1,338	1,504	419	1,171	1,590
Low Sulfur Subbituminous Coal[f]	440	458	898	1,095	440	811	1,251

[a] Includes applicable monitoring costs as shown in Table 2-15.

[b] Includes FGD malfunction costs.

[c] Assumes 95 percent FGD reliability.

[d] Assumes 90 percent FGD reliability.

[e] Heating value = 27,200 kJ/kg (11,700 Btu/lb); Sulfur content = 3.23 wt. %; Ash content 12.0 wt. %. Uncontrolled SO_2 = 2380 ng/J (5.54 lb/10^6 Btu).

[f] Heating value = 20,500 kJ/kg (8,825 Btu/lb); Sulfur content = 0.42 wt. %; Ash Content 6.9 wt. %; Uncontrolled SO_2 = 409 ng/J (0.95 lb/10^6 Btu).

exist for other regions and other boiler sizes. Dry scrubbing FGD systems are designed for combined control of SO_2 and particulate matter, whereas sodium scrubbing and double alkali FGD systems are designed for SO_2 control only. For this reason, Table 3-2 also shows the cost of a fabric filter for particulate matter control for sodium scrubbing and double alkali FGD systems. Table 3-2 shows that the capital and annualized costs of sodium scrubbing are lowest for both high and low sulfur coals. Also the capital and annualized costs of double alkali are highest for both coal types. In general, dry scrubbing costs fall between the costs of sodium scrubbing and dual alkali. In order to maintain consistency throughout this report, all FGD costs are based on sodium scrubbing. Sodium scrubbing is currently the most widely used FGD technology and its costs are considered representative of FGD costs in general.

3.1 REGION V COSTS

3.1.1 Capital Costs

The capital costs presented in this report are based on the assumption that industrial boilers will be designed specifically to fire either bituminous or subbituminous coal. The FGD system capital costs reflect the current practice of industrial boiler owners to design and install FGD systems capable of achieving 90 percent SO_2 removal on the highest sulfur coal available in order to provide maximum fuel firing flexibility.

Table 3-3 presents the capital costs of SO_2 control for 29, 44, 73, and 117 MW (100, 150, 250, and 400 million Btu/hr) model boilers firing bituminous and subbituminous coals. Capital costs for boilers at the baseline firing subbituminous coals are higher than for those firing bituminous coals due to the lower heating value of subbituminous coals which, in turn, require larger boilers in order to achieve the same heat input. Total capital costs for boilers equipped with FGD systems are also higher for subbituminous coals than for bituminous coals.

TABLE 3-3. CAPITAL COST OF SO_2 CONTROL IN REGION V ($1000) (JAN 1983 $)[a]

Boiler Size/ Coal Classification	Baseline[b]	With FGD[c]
29 MW (100 million Btu/hr)		
Bituminous	10,106	10,787
Subbituminous	10,998	11,561
44 MW (150 million Btu/hr)		
Bituminous	14,050	14,899
Subbituminous	15,200	16,001
73 MW (250 million Btu/hr)		
Bituminous	24,026	25,142
Subbituminous	25,023	25,943
117 MW (400 million Btu/hr)		
Bituminous	33,154	34,616
Subbituminous	34,379	35,578

[a]Includes applicable monitoring costs as shown in Table 2-15.

[b]Baseline costs include PM/NO_x control costs.

[c]Based on sodium scrubbing FGD.

3.1.2 Annual O&M Costs

Tables 3-4 through 3-7 present the annual O&M costs of SO_2 control for the various boiler sizes examined. These tables show that, at the baseline, fuel costs represents 50 to 60 percent of the total O&M costs for a 29 MW (100 million Btu/hr) boiler and 60 to 70 percent of the total for a 117 MW (400 million Btu/hr). For the 90 percent SO_2 removal cases, fuel costs represent about 45 to 55 percent of the total O&M costs for a 29 MW (100 million Btu/hr) boiler and about 55 to 65 percent of the total for a 117 MW (400 million Btu/hr) boiler. As expected, these tables show that the annual O&M costs at the baseline for bituminous coals increase with increasing fuel price for all boiler sizes. The annual O&M costs at the baseline for subbituminous coals are generally comparable to costs for medium sulfur bituminous coals (Types D, E, and F coals). As expected, the annualized cost of SO_2 control for boilers equipped with FGD systems increases with increasing coal sulfur content. However, total O&M costs for boilers equipped with FGD control generally track fuel price rather than sulfur content, indicating the importance of fuel price in estimating SO_2 control costs.

3.1.3 Annualized Costs

As discussed in Section 2.1.3, annualized costs are calculated as the sum of annualized capital-related charges and annual O&M costs. Tables 3-8 through 3-11 present the annualized costs of SO_2 control for the various boiler sizes and coal types examined.

These tables show that the difference in annualized costs of SO_2 control for 50 percent, 70 percent, and 90 percent FGD for a particular coal type is relatively small when compared to the total annualized costs of the boiler. These tables further show that, as expected, the annualized cost of SO_2 control increases with increasing coal sulfur content. However, the total annualized costs generally track fuel price rather than sulfur content, such that the total annualized costs of 90 percent FGD are lowest for a Type H coal for all boiler sizes examined.

TABLE 3-4. O & M COSTS FOR A 29 MW (100 MILLION BTU/HR) MODEL BOILER IN REGION V[a]
($1000/YR) (JAN 1983 $)

Coal Type	Baseline[b]			50% FGD[c]			70% FGD[c]			90% FGD[c]		
	Fuel	Other	Total	Fuel	Other	Total	Fuel	Other	Total	Fuel	Other	Total
Type B - bit	1,729	1,155	2,884	1,729	1,337	3,066	1,729	1,349	3,078	1,729	1,360	3,089
Type D - bit	1,656	1,155	2,811	1,656	1,353	3,009	1,656	1,371	3,027	1,656	1,389	3,045
Type E - bit	1,604	1,156	2,760	1,604	1,374	2,978	1,604	1,400	3,004	1,604	1,426	3,030
Type F - bit	1,526	1,157	2,683	1,526	1,399	2,925	1,526	1,434	2,960	1,526	1,469	2,995
Type G - bit	1,390	1,159	2,549	1,390	1,441	2,831	1,390	1,492	2,882	1,390	1,544	2,934
Type H - bit	1,302	1,158	2,460	1,302	1,483	2,785	1,302	1,551	2,853	1,302	1,620	2,922
Type B - sub	1,760	1,161	2,921	1,760	1,335	3,095	1,760	1,346	3,106	1,760	1,358	3,118
Type D - sub	1,739	1,162	2,901	1,739	1,350	3,089	1,739	1,368	3,107	1,739	1,386	3,125
Type E - sub	1,718	1,162	2,880	1,718	1,371	3,089	1,718	1,397	3,115	1,718	1,423	3,141

[a]Includes applicable monitoring costs as shown in Table 2-15.

[b]Baseline costs include PM/NO_x control costs.

[c]Based on the use of sodium scrubbing FGD.

TABLE 3-5. O & M COSTS FOR A 44 MW (150 MILLION BTU/HR) MODEL BOILER IN REGION V[a]
($1000/YR) (JAN 1983 $)

Coal Type	Baseline[b]			50% FGD[c]			70% FGD[c]			90% FGD[c]		
	Fuel	Other	Total	Fuel	Other	Total	Fuel	Other	Total	Fuel	Other	Total
Type B - bit	2,593	1,420	4,013	2,593	1,639	4,232	2,593	1,657	4,250	2,593	1,674	4,267
Type D - bit	2,484	1,419	3,903	2,484	1,662	4,146	2,484	1,689	4,173	2,484	1,716	4,200
Type E - bit	2,406	1,421	3,827	2,406	1,694	4,100	2,406	1,733	4,139	2,406	1,772	4,178
Type F - bit	2,289	1,423	3,712	2,289	1,731	4,020	2,289	1,784	4,073	2,289	1,837	4,126
Type G - bit	2,086	1,425	3,511	2,086	1,793	3,879	2,086	1,871	3,957	2,086	1,948	4,034
Type H - bit	1,953	1,424	3,377	1,953	1,857	3,810	1,953	2,960	3,913	1,953	2,063	4,016
Type B - sub	2,640	1,430	4,070	2,640	1,638	4,278	2,640	1,655	4,295	2,640	1,673	4,313
Type D - sub	2,609	1,429	4,038	2,609	1,661	4,270	2,609	1,688	4,297	2,609	1,715	4,324
Type E - sub	2,578	1,429	4,007	2,578	1,691	4,269	2,578	1,730	4,308	2,578	1,769	4,347

[a]Includes applicable monitoring costs as shown in Table 2-15.

[b]Baseline costs include PM/NO_x control costs.

[c]Based on the use of sodium scrubbing FGD.

TABLE 3-6. O & M COSTS FOR A 73 MW (250 MILLION BTU/HR) MODEL BOILER IN REGION V[a]
($1000/YR) (JAN 1983 $)

Coal Type	Baseline[b]			50% FGD[c]			70% FGD[c]			90% FGD[c]		
	Fuel	Other	Total	Fuel	Other	Total	Fuel	Other	Total	Fuel	Other	Total
Type B - bit	4,373	2,411	6,784	4,373	2,696	7,069	4,373	2,725	7,098	4,373	2,754	7,127
Type D - bit	4,189	2,410	6,599	4,189	2,734	6,923	4,189	2,779	6,968	4,189	2,824	7,013
Type E - bit	4,057	2,412	6,469	4,057	2,787	6,844	4,057	2,852	6,909	4,057	2,917	6,974
Type F - bit	3,860	2,417	6,277	3,860	2,850	6,710	3,860	2,938	6,798	3,860	3,027	6,887
Type G - bit	3,517	2,428	5,945	3,517	2,961	6,478	3,517	3,090	6,607	3,517	3,218	6,735
Type H - bit	3,293	2,424	5,717	3,293	3,065	6,358	3,293	3,237	6,530	3,293	3,409	6,702
Type B - sub	4,452	2,408	6,860	4,452	2,679	7,131	4,452	2,708	7,160	4,452	2,738	7,190
Type D - sub	4,400	2,407	6,807	4,400	2,717	7,117	4,400	2,762	7,162	4,400	2,807	7,207
Type E - sub	4,347	2,408	6,755	4,347	2,768	7,115	4,347	2,833	7,180	4,347	2,899	7,246

[a]Includes applicable monitoring costs as shown in Table 2-15.

[b]Baseline costs include PM/NO_x control costs.

[c]Based on the use of sodium scrubbing FGD.

TABLE 3-7. O & M COSTS FOR A 117 MW (400 MILLION BTU/HR) MODEL BOILER IN REGION V[a]
($1000/YR) (JAN 1983 $)

Coal Type	Baseline[b]			50% FGD[c]			70% FGD[c]			90% FGD[c]		
	Fuel	Other	Total	Fuel	Other	Total	Fuel	Other	Total	Fuel	Other	Total
Type B - bit	6,997	3,236	10,233	6,997	3,614	10,611	6,997	3,661	10,658	6,997	3,708	10,705
Type D - bit	6,702	3,236	9,938	6,702	3,677	10,379	6,702	3,749	10,451	6,702	3,820	10,522
Type E - bit	6,492	3,237	9,729	6,492	3,759	10,251	6,492	3,864	10,356	6,492	3,968	10,460
Type F - bit	6,175	3,247	9,422	6,175	3,862	10,037	6,175	4,004	10,179	6,175	4,145	10,320
Type G - bit	5,627	3,263	8,890	5,627	4,039	9,666	5,627	4,245	9,872	5,627	4,451	10,078
Type H - bit	5,269	3,258	8,527	5,269	4,206	9,475	5,269	4,481	9,750	5,269	4,755	10,024
Type B - sub	7,124	3,230	10,354	7,124	3,592	10,716	7,124	3,639	10,763	7,124	3,687	10,811
Type D - sub	7,040	3,230	10,270	7,040	3,654	10,694	7,040	3,726	10,766	7,040	3,798	10,838
Type E - sub	6,955	3,231	10,186	6,955	3,736	10,691	6,955	3,840	10,795	6,955	3,945	10,900

[a]Includes applicable monitoring costs as shown in Table 2-15.

[b]Baseline costs include PM/NO_x control costs.

[c]Based on the use of sodium scrubbing FGD.

TABLE 3-8. ANNUALIZED COSTS OF SO_2 CONTROL FOR A 29 MW (100 MILLION BTU/HR) MODEL BOILER IN REGION V[a,b] ($1000/YR) (JAN 1983 $)

Coal Type	Baseline[c]	50% FGD[d] SO_2[e]	50% FGD[d] Total	70% FGD[d] SO_2[e]	70% FGD[d] Total	90% FGD[d] SO_2[e]	90% FGD[d] Total
Type B - Bit	4,557	359	4,916	372	4,929	384	4,941
Type D - Bit	4,484	378	4,862	398	4,882	416	4,900
Type E - Bit	4,433	401	4,834	429	4,862	456	4,889
Type F - Bit	4,355	430	4,785	467	4,822	503	4,858
Type G - Bit	4,220	478	4,698	532	4,752	584	4,804
Type H - Bit	4,130	526	4,656	598	4,728	668	4,798
Type B - Sub	4,743	330	5,073	343	5,086	355	5,098
Type D - Sub	4,722	347	5,069	366	5,088	385	5,107
Type E - Sub	4,701	369	5,070	397	5,098	423	5,124

[a]All costs include applicable monitoring costs as shown in Table 2-15.

[b]All costs include FGD malfunction costs as discussed in Section 2.3.2.

[c]Baseline costs include PM/NO_x control costs.

[d]Based on the use of sodium scrubbing FGD.

[e]Cost of SO_2 control is incremental cost above baseline cost.

TABLE 3-9. ANNUALIZED COSTS OF SO_2 CONTROL FOR A 44 MW (150 MILLION BTU/HR) MODEL BOILER IN REGION V[a,b] ($1000/YR) (JAN 1983 $)

Coal Type	Baseline[c]	50% FGD[d] SO_2[e]	50% FGD[d] Total	70% FGD[d] SO_2[e]	70% FGD[d] Total	90% FGD[d] SO_2[e]	90% FGD[d] Total
Type B - Bit	6,344	454	6,798	472	6,816	490	6,834
Type D - Bit	6,233	485	6,718	512	6,745	540	6,773
Type E - Bit	6,156	520	6,676	560	6,716	600	6,756
Type F - Bit	6,040	561	6,601	616	6,656	670	6,710
Type G - Bit	5,838	633	6,471	712	6,550	791	6,629
Type H - Bit	5,703	706	6,409	811	6,514	917	6,620
Type B - Sub	6,607	419	7,026	438	7,045	456	7,063
Type D - Sub	6,575	445	7,020	473	7,048	501	7,076
Type E - Sub	6,544	478	7,022	518	7,062	558	7,102

[a]All costs include applicable monitoring costs as shown in Table 2-15.

[b]All costs include FGD malfunction costs as discussed in Section 2.3.2.

[c]Baseline costs include PM/NO_x control costs.

[d]Based on the use of sodium scrubbing FGD.

[e]Cost of SO_2 control is incremental cost above baseline cost.

TABLE 3-10. ANNUALIZED COSTS OF SO_2 CONTROL FOR A 117 MW (250 MILLION BTU/HR) MODEL BOILER IN REGION V[a,b] ($1000/YR) (JAN 1983 $)

Coal Type	Baseline[c]	50% FGD[d] SO_2	50% FGD[d] Total	70% FGD[d] SO_2	70% FGD[d] Total	90% FGD[d] SO_2	90% FGD[d] Total
Type B - Bit	10,751	629	11,380	659	11,410	689	11,440
Type D - Bit	10,565	678	11,243	724	11,289	770	11,335
Type E - Bit	10,433	737	11,170	804	11,237	871	11,304
Type F - Bit	10,240	806	11,046	897	11,137	988	11,228
Type G - Bit	9,905	927	10,832	1,058	10,963	1,190	11,095
Type H - Bit	9,676	1,048	10,724	1,224	10,900	1,400	11,076
Type B - Sub	10,987	585	11,572	615	11,602	645	11,632
Type D - Sub	10,934	627	11,561	673	11,607	719	11,653
Type E - Sub	10,881	682	11,563	749	11,630	816	11,697

[a]All costs include applicable monitoring costs as shown in Table 2-15.

[b]All costs include FGD malfunction costs as discussed in Section 2.3.2.

[c]Baseline costs include PM/NO_x control costs.

[d]Based on the use of sodium scrubbing FGD.

[d]Cost of SO_2 control is incremental cost above baseline cost.

TABLE 3-11. ANNUALIZED COSTS OF SO_2 CONTROL FOR A 117 MW (400 MILLION BTU/HR) MODEL BOILER IN REGION V[a,b] ($1000/YR) (JAN 1983 $)

Coal Type	Baseline[c]	50% FGD[d] SO_2[e]	50% FGD[d] Total	70% FGD[d] SO_2[e]	70% FGD[d] Total	90% FGD[d] SO_2[e]	90% FGD[d] Total
Type B - Bit	15,706	875	16,581	923	16,629	971	16,677
Type D - Bit	15,409	954	16,363	1,027	16,436	1,101	16,510
Type E - Bit	15,198	1,048	16,246	1,155	16,353	1,262	16,460
Type F - Bit	14,889	1,159	16,048	1,304	16,193	1,449	16,338
Type G - Bit	14,353	1,351	15,704	1,562	15,915	1,773	16,126
Type H - Bit	13,986	1,546	15,532	1,827	15,813	2,109	16,095
Type B - Sub	16,023	818	16,841	866	16,889	914	16,937
Type D - Sub	15,938	885	16,823	959	16,897	1,033	16,971
Type E - Sub	15,853	973	16,826	1,080	16,933	1,187	17,040

[a]All costs include applicable monitoring costs as shown in Table 2-15.

[b]All costs include FGD malfunction costs as discussed in Section 2.3.2.

[c]Baseline costs include PM/NO_x control costs.

[d]Based on the use of sodium scrubbing FGD.

[e]Cost of SO_2 control is incremental cost above baseline cost.

3.2 REGION VIII COSTS

3.2.1 Capital Costs

Table 3-12 presents the capital costs of control at the baseline and for the various SO_2 control alternatives for 29, 44, 73, and 117 MW (100, 150, 250, and 400 million Btu/hr) model boilers. A comparison of the costs in Table 3-3 with those in Table 3-12 for Region VIII shows that the capital costs for coal-fired boilers are about equal to those in Region V. Any slight differences in capital costs between the two regions are attributable to differences in fuel costs which, in turn, impact working capital requirements.

3.2.2 Annual O&M Costs

Table 3-13 presents the annual O&M costs for each of the boiler sizes examined. At the baseline level of control, fuel costs represent 35 to 45 percent of the total O&M costs for a 29 MW (100 million Btu/hr) model boiler and 45 to 55 percent for a 117 MW (400 million Btu/hr) model boiler. For the 90 percent SO_2 removal cases, fuel costs account for about 30 to 40 percent of the total O&M costs for a 29 MW (100 million Btu/hr) model boiler and about 40 to 50 percent for a 117 MW (400 million Btu/hr) model boiler. Fuel costs as a percentage of total O&M costs are lower in Region VIII than in Region V (see Section 3.1.2). This is explained by the significantly lower fuel prices in Region VIII as compared to Region V. (Table 3-1 presented the fuel prices and specifications for coals in these regions).

3.2.3 Annualized Costs

Table 3-14 presents the annualized costs of control at the baseline and for each SO_2 control alternative for the various boiler sizes examined. Annualized costs are calculated as the sum of the annualized capital charges and annual O&M costs.

Table 3-14 shows that the differences in SO_2 control costs for 50, 70 and 90 percent FGD for a particular coal type are small relative to the

TABLE 3-12. CAPITAL COST OF SO_2 CONTROL IN REGION VIII

($1000) (JAN 1983 $)[a]

Boiler Size/ Coal Classification	Baseline[b]	With FGD[c]
29 MW (100 million Btu/hr)		
Bituminous	10,062	10,728
Subbituminous	10,913	11,476
44 MW (150 million Btu/hr)		
Bituminous	13,983	14,810
Subbituminous	15,171	15,873
73 MW (250 million Btu/hr)		
Bituminous	23,913	24,993
Subbituminous	24,807	25,727
117 MW (400 million Btu/hr)		
Bituminous	32,973	34,376
Subbituminous	34,033	35,233

[a]Includes applicable monitoring costs as shown in Table 2-15.

[b]Baseline costs include PM/NO_x control costs.

[c]Based on sodium scrubbing FGD.

TABLE 3-13. O & M COSTS IN REGION VIII ($1000/YR) (JAN 1983 $)[a]

Coal Type	Baseline[b]			50% FGD[c]			70% FGD[c]			90% FGD[c]		
	Fuel	Other	Total	Fuel	Other	Total	Fuel	Other	Total	Fuel	Other	Total
29 MW (100 x 10^6 Btu/hr) model boiler												
Type B - Bit	1,036	1,158	2,194	1,036	1,341	2,377	1,036	1,353	2,389	1,036	1,365	2,401
Type D - Bit	969	1,159	2,128	969	1,358	2,327	969	1,376	2,345	969	1,394	2,363
Type E - Bit	974	1,160	2,134	974	1,378	2,352	974	1,404	2,378	974	1,430	2,404
Type B - Sub	729	1,164	1,893	729	1,338	2,067	729	1,349	2,078	729	1,361	2,090
Type D - Sub	724	1,162	1,886	724	1,351	2,075	724	1,368	2,092	724	1,386	2,110
Type E - Sub	667	1,162	1,829	667	1,371	2,038	667	1,397	2,064	667	1,423	2,090
44 MW (150 x 10^6 Btu/hr) model boiler												
Type B - Bit	1,554	1,425	2,979	1,554	1,645	3,199	1,554	1,663	3,217	1,554	1,680	3,234
Type D - Bit	1,453	1,427	2,880	1,453	1,670	3,123	1,453	1,697	3,150	1,453	1,724	3,177
Type E - Bit	1,461	1,427	2,888	1,461	1,700	3,161	1,461	1,739	3,200	1,461	1,778	3,239
Type B - Sub	1,094	1,433	2,527	1,094	1,642	2,736	1,094	1,660	2,754	1,094	1,677	2,771
Type D - Sub	1,086	1,431	2,517	1,086	1,662	2,748	1,086	1,689	2,775	1,086	1,715	2,801
Type E - Sub	1,000	1,431	2,431	1,000	1,693	2,693	1,000	1,732	2,732	1,000	1,772	2,772
73 MW (250 x 10^6 Btu/hr) model boiler												
Type B - Bit	2,621	2,416	5,037	2,621	2,702	5,323	2,621	2,732	5,353	2,621	2,761	5,382
Type D - Bit	2,450	2,420	4,870	2,450	2,745	5,195	2,450	2,790	5,240	2,450	2,835	5,285
Type E - Bit	2,463	2,421	4,884	2,463	2,796	5,259	2,463	2,861	5,324	2,463	2,926	5,389
Type B - Sub	1,844	2,424	4,268	1,844	2,695	4,539	1,844	2,725	4,569	1,844	2,754	4,598
Type D - Sub	1,831	2,410	4,241	1,831	2,719	4,550	1,831	2,763	4,594	1,831	2,808	4,639
Type E - Sub	1,686	2,410	4,096	1,686	2,771	4,457	1,686	2,837	4,523	1,686	2,902	4,588
117 MW (400 x 10^6 Btu/hr) model boiler												
Type B - Bit	4,194	3,244	7,438	4,194	3,624	7,818	4,194	3,672	7,866	4,194	3,719	7,913
Type D - Bit	3,920	3,251	7,171	3,920	3,694	7,614	3,920	3,766	7,686	3,920	3,838	7,758
Type E - Bit	3,941	3,252	7,193	3,941	3,775	7,716	3,941	3,879	7,820	3,941	3,983	7,924
Type B - Sub	2,951	3,256	6,207	2,951	3,618	6,569	2,951	3,666	6,617	2,951	3,713	6,664
Type D - Sub	2,930	3,234	6,164	2,930	3,657	6,587	2,930	3,728	6,658	2,930	3,799	6,729
Type E - Sub	2,698	3,234	5,932	2,698	3,740	6,438	2,698	3,845	6,543	2,698	3,950	6,648

[a]Includes applicable monitoring costs as shown in Table 2-15.

[b]Baseline costs include PM/NO_x control costs.

[c]Based on the use of sodium scrubbing FGD.

TABLE 3-14. ANNUALIZED COSTS OF SO_2 CONTROL IN REGION VIII ($1000/yr) (JAN 1983 $)[a,b]

Coal Type	Baseline[c]	50% FGD[d] SO_2[e]	50% FGD[d] Total	70% FGD[d] SO_2[e]	70% FGD[d] Total	90% FGD[d] SO_2[e]	90% FGD[d] Total
29 MW (100 x 10^6 Btu/hr) model boiler							
Type B - Bit	3,862	369	4,231	382	4,244	394	4,256
Type D - Bit	3,796	388	4,184	407	4,203	426	4,222
Type E - Bit	3,801	408	4,209	436	4,237	463	4,264
Type B - Sub	3,706	357	4,063	370	4,076	382	4,088
Type D - Sub	3,699	372	4,071	392	4,091	410	4,109
Type E - Sub	3,641	397	4,038	425	4,066	452	4,093
44 MW (150 x 10^6 Btu/hr) model boiler							
Type B - Bit	5,301	470	5,771	490	5,791	508	5,809
Type D - Bit	5,201	499	5,700	528	5,729	556	5,757
Type E - Bit	5,209	529	5,738	571	5,780	611	5,820
Type B - Sub	5,051	460	5,511	480	5,531	499	5,550
Type D - Sub	5,041	483	5,524	513	5,554	540	5,581
Type E - Sub	4,954	520	5,474	562	5,516	602	5,556
73 MW (250 x 10^6 Btu/hr) model boiler							
Type B - Bit	8,989	655	9,644	685	9,674	715	9,704
Type D - Bit	8,821	703	9,524	749	9,570	795	9,616
Type E - Bit	8,835	753	9,588	820	9,655	887	9,722
Type B - Sub	8,374	651	9,025	681	9,055	712	9,086
Type D - Sub	8,347	690	9,037	736	9,083	781	9,128
Type E - Sub	8,200	752	8,952	819	9,019	886	9,086
117 MW (400 x 10^6 Btu/hr) model boiler							
Type B - Bit	12,888	915	13,803	964	13,852	1,012	13,900
Type D - Bit	12,619	993	13,612	1,066	13,685	1,140	13,759
Type E - Bit	12,641	1,074	13,715	1,181	13,822	1,287	13,928
Type B - Sub	11,841	925	12,766	973	12,814	1,022	12,863
Type D - Sub	11,798	987	12,785	1,060	12,858	1,133	12,931
Type E - Sub	11,564	1,084	12,648	1,191	12,755	1,299	12,863

[a]All costs include applicable monitoring costs as shown in Table 2-15.

[b] All costs include malfunction costs as discussed in Section 2.3.2.

[c]Baseline costs include PM/NO_x control costs.

[d]Based on the use of sodium scrubbing FGD.

[e]Cost of SO_2 control is incremental cost above Baseline Cost.

total annualized cost of a boiler. Also, the total annualized cost of control tracks the fuel price rather than the sulfur content. Therefore, the least costly fuel has the lowest total annualized costs for each alternative.

3.3 REFERENCES

1. Projected Environmental, Cost and Energy Impacts of Alternative SO_2 NSPS for Industrial Fossil Fuel-Fired Boilers. (Prepared for U. S. Environmental Protection Agency). Energy and Environmental Analysis, Arlington, Virginia. July 27, 1984. pp. 9-10.

4.0 COST OF SO_2 CONTROL ON RESIDUAL OIL-FIRED MODEL BOILERS

This chapter presents the results of an analysis of SO_2 control costs for residual oil-fired model boilers. Capital and annualized costs are examined for boilers with no SO_2 control (baseline) and for boilers equipped with FGD systems achieving 50 percent, 70 percent, and 90 percent SO_2 removal. Costs are examined for several boiler sizes and for several oil sulfur contents. The boiler sizes selected for this analysis are 29, 44, 73 and 117 MW (100, 150, 250 and 400 million Btu/hr) heat input. The 117 MW (400 million Btu/hr) model boiler is actually two 59 MW (200 million Btu/hr) boilers sharing a common stack. This arrangement was selected because two small packaged units are less costly than one large field-erected unit.

Specifications and prices of residual oil delivered to Region V are presented in Table 4-1. To maintain consistency with the Industrial Fuel Choice Analysis Model (IFCAM), which is used to project the national impacts of alternative SO_2 standards, the values in Table 4-1 are projections for 1990 delivered fuel prices expressed in January 1983 dollars.[1] The projections ignore the effects of inflation but assume that fuel prices will escalate in real terms. In addition, the fuel prices have been "levelized" over the life of the boiler (i.e., an equivalent constant price has been calculated after allowing for escalation and the time value of money.

In this analysis, it is assumed that all boilers require the use of low excess air operation (LEA) for NO_x control. Costs are also presented for a model boiler using staged combustion air (SCA) operation in addition to LEA when firing a high sulfur content oil since high sulfur oil may also contain high nitrogen levels. It is also assumed that no add-on particulate matter controls are required.

The basis of the FGD costs presented in this report for residual oil-fired boilers is sodium scrubbing FGD. Sodium scrubbing FGD was selected because it is the most widely used in residual oil applications and it is generally the least costly method of control. Double alkali FGD is more costly both on a capital and an annualized basis. And dry scrubbing FGD is not considered applicable to residual oil-fired applications. Also

TABLE 4-1. SPECIFICATIONS FOR RESIDUAL OILS DELIVERED TO REGION V AND REGION VIII[a]

Sulfur Content lb $SO_2/10^6$ Btu	Fuel Price $/kJ ($/10^6 Btu)	Heating Value kJ/kg (Btu/lb)	Ash Content Wt. %	Nitrogen Content Wt. %
Region V:				
0.3	5.69 (6.01)	43,000 (18,500)	0.10	0.04
0.8	5.33 (5.63)	43,000 (18,500)	0.10	0.12
1.6	4.97 (5.25)	43,000 (18,500)	0.10	0.23
3.0	4.68 (4.94)	43,000 (18,500)	0.10	0.44
Region VIII:				
0.3	5.37 (5.67)	43,000 (18,500)	0.10	0.04
0.8	5.01 (5.29)	43,000 (18,500)	0.10	0.12
1.6	4.67 (4.93)	43,000 (18,500)	0.10	0.23
3.0	4.36 (4.60)	43,000 (18,500)	0.10	0.44

[a]Reference 1.

[b]1990 levelized fuel price in 1983 $.

the FGD costs are based on an industrial boiler located in Region V. Unlike coal all ten EPA regions have the same residual oils available. Thus the only difference in FGD costs in Region V and any other region can be attributed to fuel cost. Therefore, the cost impact of SO_2 control compared to the regulatory baseline in Region V is representative of impacts nationwide.

4.1 REGION V COSTS

4.1.1 Capital Costs

Table 4-2 presents the capital costs of SO_2 control for 29, 44, 73, and 117 MW (100, 150, 250 and 400 million Btu/hr) model boilers. The capital costs of FGD for all oil types and percent removal requirements are designed to achieve 90 percent SO_2 removal on a 3.0 lb $SO_2/10^6$ Btu oil. In other words, it is assumed that a boiler owner/operator will design an FGD for maximum fuel-firing flexibility.

4.1.2 Annual O&M Costs

Table 4-3 presents the annual O&M costs of SO_2 control for residual oil-fired model boilers in Region V. Table 4-3 shows that fuel costs represent 80 to 90 percent of the total O&M costs at the baseline and for each FGD alternative. In other words, a scrubbing requirement has little impact on the total system costs since fuel costs represent such a large percentage of the total costs.

4.1.3 Annualized Costs

Table 4-4 shows that, at the baseline and for each FGD alternative, total annualized costs decrease with increasing fuel sulfur content. Table 4-4 also shows that it is less costly to scrub a 3.0 lb $SO_2/10^6$ Btu oil than it is to fire a 0.3 lb $SO_2/10^6$ Btu oil uncontrolled for all boiler sizes examined. Furthermore, as boiler size increases, the premium price of a 0.3 lb $SO_2/10^6$ Btu oil becomes even more important and scrubbing a 0.8 lb $SO_2/10^6$ Btu oil becomes less costly than firing a 0.3 lb $SO_2/10^6$ Btu oil uncontrolled.

TABLE 4-2. CAPITAL COSTS OF SO_2 CONTROL FOR MODEL BOILERS IN REGION V[a] ($1000) (JAN 1983 $)

Boiler Size/ Coal Classification	Baseline[b]	With FGD[c]
29 MW (100 Million Btu/hr)	2,545	3,104
44 MW (150 Million Btu/hr)	3,278	3,973
73 MW (250 Million Btu/hr)	4,579	5,500
117 MW (400 Million Btu/hr)	7,732	8,998

[a]Includes applicable monitoring costs as shown in Table 2-15.

[b]Baseline costs include PM/NO_x control costs.

[c]Based on sodium scrubbing FGD.

TABLE 4-3. OPERATING AND MAINTENANCE COSTS OF SO_2 CONTROL FOR MODEL BOILERS IN REGION V[a]

($1000/YR) (JANUARY 1983 $)

	Baseline[b]			50% FGD[c]			70% FGD[c]			90% FGD[c]		
	Fuel	Other	Total	Fuel	Other	Total	Fuel	Other	Total	Fuel	Other	Total
29 MW (100×10^6 Btu/hr												
0.3 lb $SO_2/10^6$ Btu	2,847	521	3,368	2,847	677	3,524	2,847	673	3,520	2,847	677	3,524
0.8 lb $SO_2/10^6$ Btu	2,667	521	3,188	2,667	693	3,360	2,667	694	3,361	2,667	704	3,371
1.6 lb $SO_2/10^6$ Btu[d]	2,487	521	3,008	2,487	717	3,204	2,487	729	3,216	2,487	748	3,235
3.0 lb $SO_2/10^6$ Btu[d]	2,340	521	2,861	2,340	760	3,100	2,340	789	3,129	2,340	826	3,166
3.0 lb $SO_2/10^6$ Btu[e]	2,386	541	2,927	2,386	780	3,166	2,386	809	3,195	2,386	846	3,232
44 MW (150 x 10^6 Btu/hr)												
0.3 lb $SO_2/10^6$ Btu	4,241	652	4,893	4,241	801	5,072	4,241	828	5,069	4,241	834	5,075
0.8 lb $SO_2/10^6$ Btu	4,000	623	4,623	4,000	825	4,825	4,000	831	4,831	4,000	846	4,846
1.6 lb $SO_2/10^6$ Btu[d]	3,730	623	4,353	3,730	861	4,591	3,730	883	4,613	3,730	912	4,642
3.0 lb $SO_2/10^6$ Btu[d]	3,510	622	4,132	3,510	926	4,436	3,510	973	4,483	3,510	1,028	4,538
3.0 lb $SO_2/10^6$ Btu[e]	3,579	651	4,230	3,579	954	4,533	3,579	1,001	4,580	3,579	1,056	4,635
73 MW (250 x 10^6 Btu/hr)												
0.3 lb $SO_2/10^6$ Btu	7,118	816	7,934	7,118	1,035	8,153	7,118	1,045	8,163	7,118	1,054	8,172
0.8 lb $SO_2/10^6$ Btu	6,667	817	7,484	6,667	1,075	7,742	6,667	1,099	7,766	6,667	1,124	7,791
1.6 lb $SO_2/10^6$ Btu[d]	6,217	817	7,034	6,217	1,136	7,353	6,217	1,185	7,402	6,217	1,234	7,451
3.0 lb $SO_2/10^6$ Btu[d]	5,850	817	6,667	5,850	1,243	7,093	5,850	1,335	7,185	5,850	1,427	7,277
3.0 lb $SO_2/10^6$ Btu[e]	5,965	862	6,827	5,965	1,288	7,253	5,965	1,380	7,345	5,965	1,472	7,437
117 MW (400 x 10^6 Btu/hr)												
0.3 lb $SO_2/10^6$ Btu	11,388	1,368	12,756	11,388	1,635	13,023	11,388	1,650	13,038	11,388	1,664	13,052
0.8 lb $SO_2/10^6$ Btu	10,668	1,368	12,036	10,668	1,696	12,364	10,668	1,735	12,403	10,668	1,775	12,443
1.6 lb $SO_2/10^6$ Btu[d]	9,948	1,368	11,316	9,948	1,794	11,742	9,948	1,873	11,821	9,948	1,951	11,899
3.0 lb $SO_2/10^6$ Btu[d]	9,360	1,370	10,730	9,360	1,967	11,328	9,360	2,115	11,475	9,360	2,263	11,623
3.0 lb $SO_2/10^6$ Btu[e]	9,544	1,442	10,986	9,544	2,040	11,584	9,544	2,187	11,731	9,544	2,335	11,879

[a] Includes applicable monitoring costs as shown in Table 2-15.

[b] Baseline costs include NO_x control costs.

[c] Based on the use of sodium scrubbing FGD.

[d] NO_x control = Low Excess Air

[e] NO_x control = Staged Combustion Air

TABLE 4-4. ANNUALIZED COSTS OF SO_2 CONTROL FOR RESIDUAL OIL-FIRED MODEL BOILERS IN REGION V[a,b] ($1000/YR) (JANUARY 1983 $)

	Baseline[c]	50% FGD[d] SO_2[e]	50% FGD[d] Total	70% FGD[d] SO_2[e]	70% FGD[d] Total	90% FGD[d] SO_2[e]	90% FGD[d] Total
29 MW (100 x 10^6 Btu/hr)							
0.3 lb $SO_2/10^6$ Btu	3,767	252	4,019	256	4,023	260	4,027
0.8 lb $SO_2/10^6$ Btu	3,585	277	3,862	287	3,872	297	3,882
1.6 lb $SO_2/10^6$ Btu[f]	3,404	311	3,715	331	3,735	351	3,755
3.0 lb $SO_2/10^6$ Btu[f]	3,256	363	3,619	400	3,656	438	3,694
3.0 lb $SO_2/10^6$ Btu[g]	3,354	362	3,716	400	3,754	438	3,792
44 MW (150 x 10^6 Btu/hr)							
0.3 lb $SO_2/10^6$ Btu	5,408	295	5,703	301	5,709	307	5,715
0.8 lb $SO_2/10^6$ Btu	5,136	332	5,468	347	5,483	362	5,498
1.6 lb $SO_2/10^6$ Btu[f]	4,864	383	5,247	414	5,278	444	5,308
3.0 lb $SO_2/10^6$ Btu[f]	4,642	461	5,103	517	5,159	574	5,216
3.0 lb $SO_2/10^6$ Btu[g]	4,782	461	5,243	518	5,300	574	5,356
73 MW (250 x 10^6 Btu/hr)							
0.3 lb $SO_2/10^6$ Btu	8,671	351	9,022	361	9,032	370	9,041
0.8 lb $SO_2/10^6$ Btu	8,217	414	8,631	439	8,656	464	8,681
1.6 lb $SO_2/10^6$ Btu[f]	7,763	500	8,263	550	8,313	601	8,364
3.0 lb $SO_2/10^6$ Btu[f]	7,393	628	8,021	723	8,116	817	8,210
3.0 lb $SO_2/10^6$ Btu[g]	7,619	628	8,247	723	8,342	817	8,436
117 MW (400 x 10^6 Btu/hr)							
0.3 lb $SO_2/10^6$ Btu	13,994	446	14,440	461	14,455	477	14,471
0.8 lb $SO_2/10^6$ Btu	13,268	545	13,813	586	13,854	626	13,894
1.6 lb $SO_2/10^6$ Btu[f]	12,542	683	13,225	764	13,306	844	13,386
3.0 lb $SO_2/10^6$ Btu[f]	11,950	889	12,839	1,040	12,990	1,191	13,141
3.0 lb $SO_2/10^6$ Btu[g]	12,316	889	13,205	1,040	13,356	1,191	13,507

[a] Includes monitoring costs as shown in Table 2-15.

[b] Includes FGD malfunction costs as discussed in Section 2.3.2.

[c] Baseline costs include NO_x control costs.

[d] Based on the use of sodium scrubbing FGD.

[e] Cost of SO_2 control is incremental over baseline cost.

[f] NO_x Control = Low Excess Air.

[g] NO_x Control = Staged Combustion Air.

4.3 REFERENCES

1. Projected Environmental, Cost and Energy Impacts of Alternative SO_2 NSPS for Industrial Fossil Fuel-Fired Boilers. (Prepared for U. S. Environmental Protection Agency). Energy and Environmental Analysis, Arlington, Virginia. July 27, 1984. pp. 9-10.

APPENDIX A

TABLE A-1. SUMMARY OF COSTING ALGORITHMS

Routine Code[a]	Algorithm Type	Boiler Size Applicability (10^6 Btu/hr)	Table
SPRD	Boiler, spreader stoker, watertube, field-erected	60 - 200	A-4
PLVR	Boiler, pulverized coal, watertube, field-erected	$\geq$200	A-5
RNG1	Boiler, residual/natural gas, watertube, package	30 - 200	A-6
RNG2	Boiler, residual/natural gas, watertube, field-erected	200 - 700	A-7
FF	Fabric filter applied to coal-fired boiler	30 - 700	A-8
DA	Dual alkali FGD system without PM removal	All sizes	A-9
SOD	Sodium scrubbing FGD system	All sizes	A-10
DS	Lime spray drying (dry scrubbing) FGD system	All sizes	A-11
LEA	Low excess air applied to all fuel types	All sizes	A-12
SCA	Staged combustion air applied to pulverized coal-fired boiler	>150	A-13
SCA	Staged combustion air applied to residual oil-fired boiler	30 - 250	A-14
FLW	Calculates flue gas flowrates for all fuel types	All sizes	A-15

TABLE A-2. NOMENCLATURE USED IN COST ALGORITHMS

1. Capital Costs (1978 dollars)

EQUP	=	Equipment
INST	=	Installation
TD	=	Total Direct
IND	=	Indirect (Engineering, Field, Construction, Start-up, and other miscellaneous costs)
TDI	=	Total Direct and Indirect
CONT	=	Contingencies
TK	=	Turnkey
LAND	=	Land
WC	=	Working Capital
TOTL	=	Total Capital

2. Operation and Maintenance Costs[a] (1978 dollars/year)

DL	=	Direct Labor
SPRV	=	Supervision Labor
MANT	=	Maintenance Labor
SP	=	Spare Parts
ELEC	=	Electricity
UC	=	Utilities and Chemicals
WTR	=	Water
SW	=	Solid Waste Disposal
SLG	=	Sludge Waste Disposal
LW	=	Liquid Waste Disposal
SC	=	Sodium Carbonate
LMS	=	Limestone
LIME	=	Lime
FUEL	=	Fuel
TDOM	=	Total Direct Operation and Maintenance
OH	=	Overhead
TOTL	=	Total Operation and Maintenance

3. Annualized Costs (1978 dollars/year)

CR	=	Capital Recovery
WCC	=	Working Capital Charges
MISC	=	Miscellaneous (G & A, Taxes, Insurance)
TCC	=	Total Capital Charges
TOTL	=	Total Annualized Charges

TABLE A-2. (Continued)

4. Boiler Specifications

Q = Thermal Input (10^6 Btu/hr) MW)[b]
FLW = Flue Gas Flowrate (acfm) (m^3/s)[b]
CF = Capacity Factor (-)[c]
BCRF = Capital Recovery Factor for Boiler System

5. Fuel Specifications

FC = Fuel Cost ($/$10^6$ Btu) ($MJ)[b]
H = Heating Value (Btu/lb) (KJ/kg)[b]
S = Sulfur Content (percent by weight)
A = Ash Content (percent by weight)
N = Fuel Nitrogen Content (percent by weight)

6. SO_2 Control Specifications

UNCSO2 = Uncontrolled SO_2 Emissions (lb/10^6 Btu) (ng/J)[b]
CTRSO2 = Controlled SO_2 Emissions (lb/10^6 Btu) (ng/J)[b]
EFFSO2 = SO_2 Removal Efficiency (percent)
CRFSO2 = Capital Recovery Factor for SO_2 Control System

7. PM Control Specifications

UNCPM = Uncontrolled PM Emissions (lb/10^6 Btu) (ng/J)[b]
CTRPM = Controlled PM Emissions (lb/10^6 Btu) (ng/J)[b]
EFFPM = PM Removal Efficiency (percent)
CRFPM = Capital Recovery Factor for PM Control System

8. Cost Rates

ELEC = Electricity Rate ($/kw-hr)
WTR = Water Rate ($/$10^3$ gal) ($/$m^3$)[b]
ALIME = Lime Rate ($/ton) ($/kg)[b]
ALS = Limestone Rate ($/ton) ($/kg)[b]
SASH = Sodium Carbonate Rate ($/ton) ($/kg)[b]
SLDG = Sludge Disposal Rate ($/ton) ($/kg)[b]
SWD = Solid Waste Disposal Rate ($/ton) ($/kg)[b]
LWD = Liquid Waste Disposal Rate ($/$10^3$ gal) ($/$m^3$)[b]
DLR = Direct Labor Rate ($/man-hr)
SLR = Supervision Labor Rate ($/man-hr)
AMLR = Maintenance Labor Rate ($/man-hr)

TABLE A-2. (Continued)

9. Miscellaneous

S1 = Heat Specific Sulfur Removal (kg S/1000 MJ)
S2 = Time Specific Sulfur Removal (kg S/hr)
LF = Labor Factor (-)[d]

10. NO_x Control Specifications

FFAC = F-Factor (dscf/10^6 Btu)
UNCEA = Uncontrolled Excess Air (%)
CTREA = Controlled Excess Air (%)
PRCT = Percent Flame Extension Due to Staging
DELT = Change in the flue gas exit temperature due to the elimination of the air preheater or a reduction in its effectiveness.
$CRFNO_x$ = Capital Recovery Factor for NO_x Control System

[a]Cost categories are not mutually exclusive. For example, some costing routines include electricity and waste cost in the utilities category while other calculate these cost separately.

[b]FGD algorithms use metric units.

[c](-) factor presented as fraction not as percent.

TABLE A-3. CALCULATIONS COMMON TO COST ALGORITHMS

1. Capital Costs

EQUP + INST = TD[a]
IND = 0.333 * TD[b]
TDI = TD + IND
CONT = 0.20 * TDI
LAND[c] = $4000 pulverized coal boilers
= $2000 all other boilers
WC = 0.25 * (TDOM - Fuel) + 0.0833 (Fuel)[d]
TOTL = TK + LAND + WC

2. Operation and Maintenance Costs

FUEL = CF * Q * FC * 8760
TDOM = Sum of all O&M Costs other than OH
OH = 0.30 * DL + 0.26 * (DL + SPRV + MANT + SP)
TOTL = TDOM + OH

3. Annualized Costs

CR = CRF * TK
WCC = 0.10 * WC
MISC = 0.04 * TK
TCC = CR + WCC + MISC
TOTL = TCC + TOTL O&M Costs

4. Labor Factors

LF = 1 if CF > 0.7
LF = 0.5 + 2.5 * (CF - 0.5) if $0.5 \leq CF \leq 0.7$
LF = 0.5 if CF < 0.5

[a] FGD system cost algorithms compute TD without prior computation of EQUP and INST

[b] Some algorithms compute IND explicitly as a function of boiler and/or control device specifications.

[c] Only boilers have costs assumed for land.

[d] For boilers, assume a 3-month supply of all working capital components except fuel which will have a 1-month supply. For control devices, working capital is 25% of total direct operating and maintenance costs.

TABLE A-4. COST EQUATIONS FOR FIELD-ERECTED, WATERTUBE SPREADER-STOKER BOILERS

$(60\text{-}200 \times 10^6$ Btu/hr)[1]

Routine Code: SPRD

Capital Costs:

$$EQUP = \frac{Q}{7.5963 \times 10^{-8}\, Q + 4.7611 \times 10^{-5}} \left(\frac{H}{11{,}800}\right)^{-.35}$$

$$INST = \frac{Q}{8.9174 \times 10^{-8}\, Q + 5.5891 \times 10^{-5}} \left(\frac{H}{11{,}800}\right)^{-.35}$$

$$IND = \frac{Q}{1.2739 \times 10^{-7}\, Q + 7.9845 \times 10^{-5}} \left(\frac{H}{11{,}800}\right)^{-.35}$$

Annual Costs:[a]

$$DL = LF\,(202{,}825 + 5.366\, Q^2)\ (0.767)$$

$$SPRV = LF\,(136{,}900)\ (0.767)$$

$$MANT = LF\,(107{,}003 + 1.873\, Q^2)\ (0.767)$$

$$SP = (50{,}000 + 1{,}000\, Q)\ (0.767)$$

$$UC = CF\,(29{,}303 + 719.8\, Q)\ (0.848)$$

$$SW = 0.38\, CF\,(547{,}320 + 66{,}038 \ln \frac{A}{H}) \left(\frac{Q}{150}\right)^{0.9754} (0.848)$$

[a]The multipliers used, 0.767 and 0.848, are included in determining annual O&M costs. These factors reflect the economies of multiple boilers at a facility (see Chapter 2).

TABLE A-5. COST EQUATION FOR FIELD-ERECTED, WATERTUBE PULVERIZED COAL-FIRED BOILERS

(>200 x 10^6 Btu/hr)[1]

Routine Code: PLVR

Capital Costs:

$$EQUP = (4{,}926{,}066 - 0.00337\ H^2)\left(\frac{Q}{200}\right)^{0.712}$$

$$INST = 1{,}547{,}622.7 + 6{,}740.026\ Q - 0.0024133\ H^2$$

$$IND = 1{,}257{,}434.72 + 6{,}271.316\ Q - 0.00185721\ H^2$$

Annual Costs:[a]

$$DL = LF\ (244{,}455 + 1{,}157\ Q)\ (0.767)$$

$$SPRV = LF\ \left(243{,}985 - \frac{20{,}636{,}709}{Q}\right)(0.767)$$

$$MANT = LF\ (-1{,}162{,}910 + 256{,}604\ \ln Q)\ (0.767)$$

$$SP = (180{,}429 + 405.4\ Q)\ (0.767)$$

$$UC = CF\ (189{,}430 + 1476.7\ Q)\ (0.848)$$

$$SW = 0.38\ CF\ \left(-641.08 + \frac{70{,}679{,}828\ A}{H}\right)\left(\frac{Q}{200}\right)^{1.001}\ (0.848)$$

[a]The multipliers used, 0.767 and 0.848, are included in determining annual O&M costs. These factors reflect the economies of multiple boilers at a facility (see Chapter 2).

TABLE A-6. COST EQUATIONS FOR PACKAGE, WATERTUBE DUAL-FIRED BOILERS FIRING RESIDUAL OIL/NATURAL GAS

$(30\text{-}200 \times 10^6$ Btu/hr)[1]

Routine Code: RNG1

Capital Costs

EQUP = $15{,}925\ Q^{.775}$

INST = $54{,}833\ Q^{0.364}$

IND = $16{,}561\ Q^{.613}$

Annual Costs[a]

DL = $LF\left(\frac{Q^2}{8{,}135 \times 10^{-4}\ Q - 1.585 \times 10^{-2}}\right)$ (0.799)

SPRV = LF (68,500) (0.799)

MANT = $LF\left(\frac{-1{,}267{,}000}{Q}\right)$ + 77,190) (0.799)

SP = $7{,}185\ Q^{0.4241}$ (0.799)

UC = $\frac{CF}{.55}$ (202 Q + 24,262) (0.845)

[a]The multipliers used, 0.799 and 0.845, are included in determining annual O&M costs. These factors reflect the economies of multiple boilers at a facility (see Chapter 2).

TABLE A-7. COST EQUATIONS FOR FIELD-ERECTED, WATERTUBE RESIDUAL OIL/GAS-FIRED BOILERS

$(200 - 700 \times 10^6$ Btu/hr)[1]

Routine Code: RNG2

Capital Costs:

EQUP = 1,024,258 + 8,458 Q

INST = 579,895 + 5,636 Q

IND = 515,189 + 4,524 Q

Annual Costs:[a]

DL = LF (173,197 + 734 Q) (0.799)

SPRV = $LF\left(263{,}250 - \frac{30{,}940{,}000}{Q}\right)(0.799)$

MANT = LF (32,029 + 320.4 Q)(0.799)

SP = (50,000 + 250 Q) (0.799)

UC = CF (43,671.7 + 479.6 Q) (0.845)

[a]The multipliers used, 0.799 and 0.845 are included in determining annual O&M costs. These factors reflect the economies of multiple boilers at a facility (see Chapter 2).

TABLE A-8. COST EQUATIONS FOR FABRIC FILTERS APPLIED TO COAL-FIRED BOILERS

$(30 - 700 \times 10^6 \text{ Btu/hr})^2$

Routine Code: FF

Capital Costs:

EQUP	=	$8.340\ (FLW)^{0.966}$	
INST	=	$-1{,}506{,}523 + 168{,}531\ \ln (FLW)$	
IND	=	$24.990\ (FLW)^{0.821}$	

Annual Costs:

DL	=	$LF\ (10{,}150 + 106\ Q)$	if $30 < Q < 400$
	=	$LF\ (52{,}600)$	if $400 < Q \leq 700$
SPRV	=	0	if $30 < Q \leq 400$
	=	$LF\ (17{,}000)$	if $400 < Q \leq 700$
MANT	=	$LF\ (14{,}840 + 0.106\ Q^2)$	if $30 < Q \leq 400$
	=	$LF\ (32{,}000)$	if $400 < Q \leq 700$
SP	=	$0.278\ (FLW)^{0.997}$	
ELEC	=	$\left(\frac{CF}{0.6}\right)\ 0.740\ (FLW)^{0.953}$	
SW	=	$\left(\frac{CF}{0.6}\right)\ 39.42\ Q\ (UNCPM - CTRPM)$	

TABLE A-9. COST EQUATIONS FOR DUAL ALKALI FGD SYSTEMS WITHOUT PM REMOVAL[a]

Routine Code: DA

Capital Costs:[b,c]

$TD = 35{,}500\ (FLW)^{0.61} + 83{,}118\ (S2)^{0.39}$

$TK = 1.48\ TD + 93{,}600$ if $Q \leq 58.6$

$= 1.48\ TD + 130{,}000$ if $Q > 58.6$

Annual Costs:[b,c]

$DL = 8{,}760 * DLR * LF$

$SPRV = 1{,}314 * DLR * LF$

$MANT = 0.08\ TD * LF$

$ELEC = 8{,}760\ CF * ELEC\ [2.94\ FLW\ (0.121\ S1 + 0.861)]$

$WTR = 8{,}760\ CF * WTR\ [0.197\ FLW + 0.30] * [0.977 + 0.119\ \ln S1]$

$SW = 8{,}760\ CF * SWD\ [7.73\ S2 - 3.34]$

$SC = 8{,}760\ CF * SASH\ [1.13\ FLW - 2.06] * [0.41 - 0.70\ (0.24 - S1)^{1.74}]$ if $S1 < 0.24$

$= 8{,}760\ CF * SASH\ [1.13\ FLW - 2.06] * [0.70\ (S1 - 0.24)^{1.74} + 0.41]$ if $S1 \geq 0.24$

$LIME = 8{,}760\ CF * ALIME\ [1.61\ S2 - 0.85]$

[a] FGD algorithms use metric units as noted in Table A-2.

[b] $S1 = S * EFFSO2 * 100/H$.

[c] $S2 = S1 * Q * 3.6$

TABLE A-10. COST EQUATIONS FOR SODIUM SCRUBBING FGD SYSTEMS[a]

Routine Code: SOD[b,c]

Capital Costs:[d]

$TK_s = 39{,}900\ (FLW)^{0.585} + 1{,}370\ (S2)^{0.727}$

$TK_w = 26{,}500\ S_2^{\ 0.39}$

$TK = TK_s + TK_w$

Annual Costs:

DL = 1,100*DLW

SPRV = 165*SPRV

MANT = 0.08*TK

$ELEC_s$ = 8,760*CF*ELEC [3.61(FLW) - 2.15]

$ELEC_w$ = 8760*CF*ELEC [0.23(S2) + 1.32]

ELEC = $ELEC_s + ELEC_w$

WTR = 8760*CF*WTR [0.600(FLW) - 2.08] [0.527(S1) + 0.364]

SC = 8760*CF*SASH [3.33(S2) + 0.082]

LW = 8760*CF*LWD [0.0616(S2) + 0.298][e]

[a] All FGD algorithms are in metric units as noted in Table A-2.

[b] $S1 = S*EFFSO_2*100/H$

[c] S2 = S1*Q*3.6

[d] The subscript "s" denotes scrubber costs and the subscript "w" denotes wastewater costs.

[e] This equation assumes that the wastewater stream has a total dissolved solids concentration (TDS) of 5.7.

TABLE A-11. COST EQUATIONS FOR LIME SPRAY DRYING FGD SYSTEMS WITH PM REMOVAL[a]

Routine Code: DS

Capital Costs:[b,c]

$TD = C1 + C2 + C3 + C4$

$C1 = 55{,}600\ (FLW)^{0.51}$

$C2 = 32{,}900\ (S2)^{0.40}$

$C3 = 18{,}400 + 8{,}260\ (FLW) + 6{,}420\ (FLW)^{0.50}$

$C4 = 256{,}320\ [W1 + W2]^{0.63}$

$W1 = Q * S/H * [0.626\ EFFSO2 - 79.9\ ln\ (1-EFFSO2/100) - 10.1]$

$W2 = 3.96 \times 10^{-6} Q\ (UNCPM - CTRPM)$

$TK = 1.48\ TD + 110{,}400$ if $Q \leq 58.6$

$= 1.60\ TD$ if $Q > 58.6$

Annual Costs, $/Year

$DL = 8{,}760 * DLW * LF$

$SPRV = 1{,}314 * SPRV * LF$

$MANT = [0.08\ [55{,}600\ (FLW)^{0.51} + 32{,}900(S2)^{0.40}] + M1 + M2] * LF$

$M1 = 834\ FLW$

$M2 = MANT * (4.04\ FLW + 1{,}086)$

$ELEC = 8{,}760\ CF * ELEC\ [6.14\ (FLW)^{0.82}]$

$WTR = 8{,}760\ CF * WTR\ [0.144\ FLW]$

$SW = 8{,}760\ CF * SWD\ [W3 + W4]$

$W3 = (Q * S/H) * [569\ EFFSO2 - 72{,}700\ ln\ (1-EFFSO2/100) - 9{,}230]$

$W4 = 3.6 \times 10^{-3} Q\ (UNCPM - CTRPM)$

$LIME = 8{,}760\ CF * ALIME * (-48{,}500) * Q * S/H * [ln\ (1-EFFSO2/100) + 0.127]$

[a] FGD algorithms use metric units as noted in Table A-2.

[b] $S1 = S * EFFSO2 * 100/H$.

[cd] $S2 = S1 * Q * 3.6$.

TABLE A-12. COST EQUATIONS FOR LOW EXCESS AIR APPLIED TO INDUSTRIAL BOILERS

Routine Code: LEA

Capital Costs:

Coal: EQUIP = 46.22(Q) + 6496
INST and IND = 21.50(Q) + 1123

Oil and Gas: EQUIP = 31.38(Q) + 5185
INST and IND = 11.37(Q) + 1161

Annual Costs:

SP^b = 0.05 (TK)
FUEL = -.00055(FC)(Q)(CF)(FFAC)(UNCEA - CTREA)

[a]Algorithm assumes a flue gas temperature of 400°F and the ambient air temperature to be 77°F.

[b]Spare parts costs consist of the costs for spare parts, maintenance labor, and maintenance materials.

TABLE A-13. COST EQUATIONS FOR STAGED COMBUSTION AIR APPLIED TO PULVERIZED COAL-FIRED BOILERS

(>150 x 10^6 Btu/hr)

Routine Code: SCA

Capital Costs:

EQUIP = 65 (Q) + 13000
INST and IND = 60 (Q) + 2000

Annual Costs:

SP[a] = 0.05 (TK)
ELEC = 105 (Q)(CF)
FUEL = 21.9 (FC)(Q)(CF)

[a] Spare parts costs consist of the costs for spare parts, maintenance labor, and maintenance materials.

TABLE A-14. COST EQUATIONS FOR STAGED COMBUSTION AIR APPLIED TO RESIDUAL OIL-FIRED BOILERS (fuel N >0.23 wt. percent)

(30 - 250 x 10^6 Btu/hr)

Routine Code: SCA

Capital Costs:

$$TK = 1000 [(Q)(PRCT)\ 0.0536 + 2.56\ (PRCT)]$$

where:

PRCT = 30; when N >0.6
PRCT = 81.1(N) - 18.7 when 0.23 <N <0.6

Annual Costs:

SP[a] = 0.05 (TK)
ELEC = 102 (Q)(CF)
FUEL = 21.9 (FC)(Q)(CF)

[a]Spare parts costs consists of the costs for spare parts, maintenance labor, and maintenance maerials.

TABLE A-15. FLUE GAS FLOWRATE ALGORITHMS[a,b]

Natural Gas		
FLW = 8.14×10^6 Q/H	(non-LEA)	
FLW = 6.81×10^6 Q/H	(LEA)	
Distillate and/or Residual		
FLW = $0.189\ Q\ H^{0.77}$	(non-LEA)	
FLW = $0.156\ Q\ H^{0.77}$	(LEA)	
Coal (Stoker)		
FLW = EXP $[8.14 \times 10^{-5} H] * 1.84 \times 10^6$ Q/H	(non-LEA)	
FLW = EXP $[8.14 \times 10^{-5} H] * 1.66 \times 10^6$ Q/H	(LEA)	
Coal (Pulverized)		
FLW = 1.62×10^6 * EXP $[8.03 \times 10^{-5} H]$ * Q/H	(LEA)	
FBC (Pulverized Coal)		
FLW = 297.82Q		

[a] LEA and non-LEA conditions are defined as follows:

NG and oil: LEA - 15% excess air
Non-LEA - 40% excess air

Coal: LEA - 35% excess air for stokers and 30% excess air pulverized coal.
Non-LEA - 50% excess air

[b] Flue gas flowrate in acfm.

APPENDIX B

TABLE B-1. COST ESCALATION FACTORS

Capital Costs

$$\text{Capital Cost Escalation Factor} = \frac{\text{index for update year}}{\text{index for July 1978}}$$

	CE Plant Index[a]
July 1978	219.2
Jan. 1979	229.8
July 1979	239.3
Jan. 1980	247.5
July 1980	263.6
Jan. 1981	276.6
July 1981	303.1
Jan. 1982	311.8
July 1982	314.2
Jan. 1983	315.5

Operating and Maintenance Costs

$$\text{O \& M Cost Escalation Factor} = \frac{\text{index for update year}}{\text{index for July 1978}}$$

	Producer Price Index[b]
July 1978	210.1
Jan. 1979	220.0
July 1979	237.5
Jan. 1980	260.6
July 1980	276.2
Jan. 1981	291.5
July 1981	306.2
Jan. 1982	311.8
July 1982	312.8
Jan. 1983	313.9

TABLE B-1 COST ESCALATION FACTORS (Continued)

[a]Economic Indicators. Chemical Engineering. 85 (23): 7, October 23, 1978; 85 (11): 7, May 8, 1978; 86 (24): 7, November 5, 1979; 86 (10): 7, May 7, 1979; 87 (23): 7, November 17, 1980; 87 (9): 7, May 5, 1980; 88 (23): 7, November 16, 1984; 88 (10): 7, May 18, 1981; 89 (23): 7, November 15, 1982; 89 (10): 7, May 17, 1982; 90 (24): 7, November 28, 1983; 90 (11): 7, May 30, 1983.

[b]BLS Producer Price Index. All Industrial Commodities. File 176, Dinlog Information Services, Inc. July 26, 1984 update.